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THE SOLAR AND GEOTHERMAL POWER PRODUCTION INCENTIVES ACT OF 1990

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

SECOND SESSION

ON

S. 2415

TO ENCOURAGE SOLAR AND GEOTHERMAL PRODUCTION BY REMOVING THE SIZE LIMITATIONS CONTAINED IN THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

MAY 15, 1990

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THE SOLAR AND GEOTHERMAL POWER PRODUCTION INCENTIVES ACT OF 1990

TUESDAY, MAY 15, 1990

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 10:35 a.m., in room SD-366, Dirksen Senate Office Building, Hon. J. Bennett Johnston (chairman) presiding.

OPENING STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

The CHAIRMAN. My apologies for the late start. I have been over on the floor trying to work out a time agreement on the Tongass National Forest, with no success so far.

We are here this morning to receive testimony on S. 2415, the Solar and Geothermal Power Production Incentives Act of 1990. This legislation would remove all size restrictions applicable to solar and geothermal, qualifying small power production facilities under PURPA.

When PURPA was enacted in 1978, there was little expectation that QFs would be significant sources of new generating capacity. Nevertheless, astonishing growth has occurred, and we now have about 27,000 megawatts of QF capacity on line, or between 3 and 4 percent of the national electric capacity. Most of that growth has been in cogeneration, but some of it has been in small power production.

This is not the first time since the enactment of PURPA that Congress has been asked to make adjustments in the law as it pertains to the small power producers.

In 1980, as part of the Energy Security Act, we allowed geothermal facilities to receive regulatory exemption under PURPA, all the way up to 80 megawatt ceiling on small power production. In 1988 as part of the continuing resolution, we provided similar treatment for solar facilities that were certified or noticed during the two year period following enactment. I think that as we embark upon our third time of dealing with the size limitations, we should ask some hard questions.

The idea behind small power production was that renewable resources needed a boost but not a handout. It is reasonable, therefore, to ask what progress has been made in the cost of renewable technologies. The bill affects geothermal and solar facilities, and we will be asked to include wind as well.

Are these serious resources or tinker toy solutions that will never yield significant benefits? Few would disagree that in the early days of PURPA, QFs generally received outright subsidies paid for by consumers. I do not think we can afford such a policy anymore. Therefore, it is important to find out how solar, geothermal and wind are being treated by state commissions today. Are these technologies competing with conventional resources as they should, or are consumers still footing the bill?

Finally, what will the future bring? Can we look forward to the day when solar, wind and geothermal stand completely on their own without the need for QF status?

We have an excellent panel of witnesses this morning, and I look forward to hearing them. And we begin with J. Michael Davis, Assistant Secretary for Conservation and Renewable Energy from DOE.

We have an opening statement by Senator Domenici first.

[The text of S. 2415 follows:]

101st CONGRESS
2d Session

S. 2415

To encourage solar and geothermal power production by removing the size limitations contained in the Public Utility Regulatory Policies Act of 1978.

IN THE SENATE OF THE UNITED STATES

April 4 (legislative day, January 23), 1990

Mr. Domenici (for himself, Mr. McClure, Mr. Wirth, Mr. Reid, Mr. McCain, and Mr. Bryan) introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

---

A BILL

To encourage solar and geothermal power production by removing the size limitations contained in the Public Utility Regulatory Policies Act of 1978.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Section 1. This Act may be cited as "The Solar and Geothermal Power Production Incentives Act of 1990".

Sec. 2. Section 210 of the Public Utility Regulatory Policies Act of 1978 is amended as follows:

(a) In subsection (a), by striking out ", and to encourage geothermal small power production facilities of not more than 80 megawatts capacity,".

★(Star Print)

(b) In subsection (e)(2), by inserting "(other than a qualifying small power production facility which is a solar or geothermal facility as defined in section 3(17)(E) of the Federal Power Act)" after "facility" where it first appears, and by striking and ", or 80 megawatts for a qualifying small power production facility using geothermal energy as its primary energy source,".

SEC. 3. (a) Section 3(17)(A) of the Federal Power Act is amended by inserting "a facility which is a solar or geothermal facility, or" after "'small power production facility' means".

(b) Section 3(17) of such Act is further amended by inserting at the end thereof the following new subparagraph:

> "(E) 'solar or geothermal facility' means a facility which produces electric energy solely by the use, as a primary energy source, of solar energy or geothermal resources;".

SEC. 4. (a) Within thirty days of the date of enactment of this Act, the Federal Energy Regulatory Commission shall issue such proposed modifications to its regulations as may be necessary to implement the amendments made by this section, and within ninety days of such date, the Commission shall issue final regulations.

(b) Until regulations described in subsection (a) are final and effective, any solar or geothermal facility (as defined in section 3(17)(E) of the Federal Power Act), which is a qualifying small power production facility as defined in subparagraph (C) of section 3(17) of the Federal Power Act (as such section 3(17) is amended by this Act), (A) shall be considered a qualifying small power production facility under part 292 of title 18 of the Code of Federal Regulations, notwithstanding any size limitations contained in such part, and (B) shall not be subject to the size limitation contained in section 292.601(b) of such part.

STATEMENT OF HON. PETE V. DOMENICI, U.S. SENATOR FROM NEW MEXICO

Senator DOMENICI. First, Mr. Chairman, I want to thank you for holding this hearing on S. 2415. I particularly want to thank Senator McClure, ranking Republican, and Senators Reid, McCain, Bryan, and Cranston for co-sponsoring this bill.

The legislation before this Committee can be summarized very simply. It only proposes to remove PURPA size restrictions for solar and geothermal power plants.

Under PURPA, a new solar facility cannot be built larger than 30 megawatts, and a new geothermal cannot be built larger than 80, without losing its PURPA regulatory benefits.

These benefits include an exemption from the Public Utility Holding Company Act and the Federal Power Act as well as mandatory interconnections and power purchases at full avoided costs. I will say a little more about the competitive nature of this which the Chairman has raised in a moment.

For all practical purposes, without PURPA benefits, these environmentally benign power plants cannot be built. It is only appropriate to consider this legislation contemporaneously with congressional action on global warming and clean air because solar and geothermal power plants offer clean and dramatic air quality benefits.

The geothermal facilities have no combustion-related emissions, and even with the use of natural gas as a backup, solar facilities offer significant reductions per kilowatt of power produced.

Solar technology has evolved rapidly since the first utility-scale electric generating facility, 1984 or thereabouts. About 300 megawatts of solar electric capacity have been put into operation, and these plants have won high praise for both their design and their reliability from the utilities which purchased the power.

Geothermal technology has similarly demonstrated both cost effectiveness and reliability. Over 2,000 megawatts of geothermal generating capacity are currently in service. Given the technological changes which have taken place since PURPA about a decade ago, PURPA's size restrictions now unduly limit the development of solar and geothermal power plants. Solar power must gain economies of scale associated with larger facilities to compete with fossil fuel alternatives, and for geothermal power to fully utilize geothermal reservoirs, it is necessary that these facilities be in excess of the 80 megawatts to be located in proximity to each other. But in a recent order, the Federal Energy Regulatory Commission clearly indicated that its hands are tied by PURPA, and Congress would have to act. That is what I think we ought to do.

One of the ironies is that unlike solar and geothermal plants, fossil fuel-fired cogenerators of any size are eligible for qualifying status under PURPA. In addition, conventional gas-fired power plants are increasingly entering the power supply as independent power producers, again without any size limitation.

Competition in the wholesale power supply market is intense and growing. Generally speaking, power purchase contract rates for PURPA and the qualifying facilities are determined either through formal bidding or highly competitive negotiations, rather than by use of the mandatory purchase requirement and full avoided cost standard. I think that is very important, and I hope the witnesses will describe how that it working for us.

In short, the power sold under future contracts for qualifying facilities will be at truly competitive rates without rate payer subsidy. I believe that is the case. In order for renewable facilities to remain competitive at a time of low fossil fuel prices and persistently high interest rates, it has been essential to improve the cost and performance of these technologies over a very short time period.

For example, solar facilities built in 1984 generate electricity at a life cost cycle of 24 cents per kilowatt hour. In contrast, the most recent solar power, an 80 megawatt facility placed in service at the end of 1989, five years, has a life cycle cost of eight cents per kilowatt hour. To participate in tomorrow's electric power generating market, it is essential that the cost of solar power drop even further to roughly six cents per kilowatt hour.

By removing PURPA size limit, applicable to solar, this legislation will permit solar power to take full advantage of the technological developments to achieve additional cost reductions. And if they can be achieved, which I fully expect they will, solar energy will be fully price competitive with conventional powerplants.

I think we all want to confirm these observations during this hearing. There can be no doubt that this legislation will help us with our energy independence. For example, over 30 years each 80 megawatts of solar-generating capacity backs out the equivalent of 14 million barrels of foreign oil, and geothermal facilities will likewise help reduce this dependency.

So, I look forward to this hearing and I look forward to passing this bill, either as part of Senator Wirth's bill, which will be my intention when we mark it up, or free-standing or both, but I think it is time for a change.

Thank you, Mr. Chairman.

[The prepared statement of Senator Domenici follows:]

Statement of

Senator Pete V. Domenici (R-NM)

Committee on Energy and Natural Resources
Hearing On S. 2415
The Solar and Geothermal Power Production
Incentives Act of 1990

May 15, 1990

I want to thank Senator Johnston for holding today's hearing on S. 2415, the Solar and Geothermal Power Production Incentives Act of 1990. I particularly want to thank Senator McClure, the Committee's ranking Republican, and Senators Wirth, Reid, McCain, Bryan and Cranston for cosponsoring my bill.

The legislation before the Committee today can be summarized very simply; it only proposes to remove PURPA's size restrictions for solar and geothermal power plants.

Under PURPA, a new solar facility cannot be built larger than 30 megawatts, and a new geothermal facility cannot be built larger than 80 megawatts, without losing its PURPA regulatory benefits. These benefits include an exemption from the Public Utility Holding Company Act and the Federal Power Act, as well as mandatory interconnection and power purchase at full avoided cost. And for all practical purposes, without PURPA benefits these environmentally benign power plants cannot be built.

It is only too appropriate to consider this legislation contemporaneously with Congressional action on both the global warming bill and the clean air legislation because solar and geothermal power plants offer clear and dramatic air quality benefits. Geothermal facilities have no combustion-related emissions; and even with the use of natural gas as a back up source of energy, solar facilities offer very significant emission reductions per kilowatt of power produced.

Solar technology has evolved rapidly since the first utility-scale electric generating facility was placed in service back in 1984. Nearly 300 megawatts of solar electric capacity have since been put into operation, and these plants have won high praise for both their design and reliability from the utility which purchases the power.

Geothermal technology has similarly demonstrated both cost-effectiveness and reliability. Over 2,000 megawatts of geothermal generating capacity are currently in service in the United States.

Given technological changes which have taken place since PURPA was enacted more than a decade ago, PURPA's size restrictions now unduly limit the development of solar and geothermal power plants. Solar power plants must gain economies of scale associated with larger facilities in order to compete with fossil fuel alternatives; and for geothermal power plants to fully utilize geothermal reservoirs, it is necessary for facilities in excess of 80 megawatts to be located in close proximity to each other. But in a recent order, the Federal Energy Regulatory Commission clearly indicated that its hands are tied by PURPA, and that Congress would have to act if such co-location and larger sizes are to be allowed.

Perhaps one of the ironies of PURPA is that unlike solar and geothermal power plants, fossil fuel-fired cogenerators of any size are eligible for qualifying status under PURPA. In addition, conventional gas-fired power plants are increasingly entering the power supply market as independent power producers, again with no size limit.

Competition in the wholesale power supply market is intense and growing. Generally speaking, power purchase contract rates for PURPA qualifying facilities are determined either through formal bidding or highly competitive negotiations, rather than by use of PURPA's mandatory purchase requirement and full avoided cost standard. In short, the power sold under future contracts for qualifying facilities will be at truly competitive rates without ratepayer subsidy.

In order for renewable facilities to remain competitive at a time of low fossil fuel prices and persistently high interest rates, it has been essential to drastically improve the cost and performance of these technologies over a very short period of time. For example, solar facilities built in 1984 generate electricity at a life cycle cost of 24 cents per kilowatt hour. In contrast, the most recent solar power plant, an 80 megawatt facility placed in service at the end of 1989, has a lifecycle cost of only 8 cents per kilowatt hour.

To participate in tomorrow's electric power generation market, it is essential that the cost of solar power production drop even further, to roughly 6 cents per kilowatt hour. By removing PURPA's size limit applicable to solar facilities, this legislation will permit solar power to take full advantage of technological developments to achieve additional cost reductions. And if they can be achieved, which I fully expect they will, solar energy will be fully price competitive with conventional power plants.

In terms of our national energy policy, it is important that we take reasonable steps to encourage a wide variety of options to help meet this Nation's energy needs in the future. We will never find a single or simple answer to our growing dependency on imported energy, but incremental steps to promote domestic energy production are very important and must be taken.

This legislation will take such steps; and they will help! For example, over thirty years, each 80 megawatts of solar generating capacity backs out the equivalent of 14 million barrels of foreign oil; and geothermal facilities will likewise help reduce our foreign energy dependency.

As a Senator from sunny New Mexico, I look forward to the day when my State will more fully utilize its abundant solar resources to generate electricity.

Again, I want to thank the Chairman for holding this hearing; and I hope and expect that we will move this bill quickly through the Committee and the Senate. I ask unanimous consent that S. 2415 and the full text of my introductory statement be included in the record at this point.

Statement of
Senator Pete V. Domenici (R-NM)
on the introduction of

The Solar and Geothermal Power Production Incentives Act of 1990

Mr. President, along with Senators McClure, Wirth, Reid, McCain and Bryan, I am introducing legislation to remove the size restrictions contained in the Public Utility Regulatory Policies Act of 1978 (PURPA) for solar and geothermal power plants. Under PURPA, a new solar facility larger than 30 megawatts, or a new geothermal facility larger than 80 megawatts, cannot be built without losing its PURPA regulatory benefits; and, for all practical purposes, without those benefits solar and geothermal power plants cannot be built.

PURPA's size limitations on solar and geothermal power plants are no longer necessary or appropriate, and they unduly limit the development of these facilities. It is time they be removed, which is what this legislation proposes to do.

It had originally been my intention to offer this legislation as an amendment to the Clean Air Act amendments, but at the request of the Chairman of the Committee on Energy and Natural Resources I am instead introducing this as a free-standing bill. Senator Johnston has assured me that this legislation will be brought before the Committee in a timely manner, and that hearings and Committee action can be expected.

Mr. President, this is not the first time the Congress has addressed this issue. Since its enactment in 1978, on several occasions it has been necessary to relax PURPA's size restrictions to reflect the increased capabilities of maturing technologies. PURPA was amended in 1980 to increase from 30 to 80 megawatts the size limitation for geothermal facilities, and two and a half years ago there was temporary legislation enacted to allow QF solar facilities to increase in size from 30 to 80 megawatts without losing their PURPA benefits. Without those changes, economies of scale would not have been available for solar and geothermal projects and the power would have been unnecessarily expensive, or projects might not have been economically feasible. Obviously, neither of those results would have been in the public interest.

For solar energy projects it is particularly necessary to revisit the size limitation. Legislation enacted in 1987 increased the size limitation to 80 megawatts for QF solar facilities, but that was limited to facilities which made certain filings to the Federal Energy Regulatory Commission within two years of enactment. With the passage of time, the window of opportunity created by that legislation is now closed, and it is therefore again necessary for us to take action if cost-effective solar projects are to be built.

Solar and geothermal electric generating facilities offer clear and dramatic air quality benefits and therefore should be encouraged. Geothermal facilities have no combustion related emissions, and even with the use of a limited amount of natural gas as a back-up source of energy, solar facilities offer very significant emission reductions even when compared to the cleanest conventional alternative, that of natural gas. Carbon dioxide emissions are .27 pounds per kilowatt hour for a solar facility, as compared to 1.1 pounds for a natural gas fired power plant; and NOx emissions are .07 pounds per megawatt hour for a solar facility, as compared to 1.4 pounds at a gas fired power plant.

Solar technology has evolved rapidly since the first utility-scale electric generating facility was placed in service in 1984. Nearly 300 megawatts of solar electric capacity have since been placed in service, and these plants have won high praise from the utility which purchases power from them; praise for both the design and the reliability of solar power plants.

Similarly, geothermal technology has demonstrated both cost effectiveness and reliability. Over 2000 megawatts of geothermal generating capacity are currently in service in the United States, and more can be put on line if we adopt the legislation I am introducing today.

At this point in time, PURPA size limitations are the principal barriers limiting solar and geothermal technology. Solar power plants must gain economies of scale associated with larger facilities in order to compete with fossil fuel alternatives. For geothermal power plants to fully utilize geothermal reservoirs, it is necessary for facilities in excess of 80 megawatts to be located in close proximity. But in a recent Order, the Federal Energy Regulatory Commission indicated the need for Congressional action if such co-location were to be allowed.

In contrast, fossil fuel fired cogenerators are today eligible for qualifying status under PURPA with no size limit. In addition, conventional gas plants are increasingly entering the power supply market as independent power producers, also with no size limit.

Competition in the power supply market is intense and growing. Today, power purchase contract rates are determined either through formal bidding or highly competitive negotiations, and PURPA QF facilities now have little, if any, advantage in competition with other power producers. In short, the power sold under future contracts will be at truly competitive rates without subsidy.

In order for renewable facilities to remain competitive at a time of low fossil fuel prices and persistent high interest rates, it has been essential to drastically improve the cost and performance of these technologies over a very short period of time. For example, solar facilities built in 1984 generate electricity at a lifecycle cost of 24 cents per kilowatt hour. In contrast, the most recent solar power plant, an 80 megawatt facility placed in service at the end of 1989, has a lifecycle cost of only 8 cents per kilowatt hour; and if this legislation is signed into law, even lower costs of generation can be expected.

To participate in today's highly competitive electric power generation market, it is essential that the cost of solar power production drop even further, to roughly 6 cents per kilowatt hour. By removing the size limit applicable to solar facilities, this amendment will permit solar power plants to take advantage of the best opportunity to achieve these additional savings, and at 6 cents, solar energy will be fully competitive with conventional power plants.

It only takes a moment to describe the legislation: it removes the statutory size limitations applicable to solar and geothermal facilities under PURPA. In all other regards, a qualifying solar or geothermal facility will be treated the same under PURPA and other applicable law.

Although this legislation would take effect immediately upon enactment, in order to insure that there will be no disruption while new regulations are issued, the bill would expand the scope of existing FERC regulations to encompass larger solar and geothermal facilities (except that limitations contained in existing regulations related to size will not apply). In particular, 18 C.F.R. 292.204(a), which addresses size limitations for qualifying status, and 18 C.F.R. 292.601(b), which addresses size limitations for the purpose of exemption from utility-type regulation, will not apply. And in order to give the solar and geothermal industries and potential project investors clear and consistent guidance and regulatory certainty, the bill also calls for an expedited rulemaking by FERC to make such modifications to its regulations as may be needed.

In terms of our national energy policy, it is important that we take reasonable steps to encourage a wide variety of options to help meet this Nation's energy needs in the future. We will never find a single or simple answer to our dependency on imported oil, but incremental steps to promote domestic energy production are very important. This legislation will make several such steps possible. For example, over thirty years, each 80 megawatts of solar generating capacity backs out the equivalent of 13.9 million barrels of foreign oil, and geothermal facilities will contribute likewise to reducing our foreign oil dependency.

This legislation will allow market and technological forces, rather than government regulations, to determine the economically optimal size for renewable energy facilities, thereby enabling these technologies to realize significant additional cost reductions. Improved economic performance will increase our utilization of renewable resources, benefit our air quality and enhance our energy security.

As a Senator from sunny New Mexico, I look forward to the day when my State will more fully utilize its abundant solar resources to generate electricity. This proposal has broad support on both sides of the aisle and I am confident that Committee and Senate action will be favorable.

Mr. President, it is for these reasons I am today introducing this legislation and I urge my colleagues to cosponsor it.

STATEMENT OF HON. JAMES A. McCLURE, U.S. SENATOR FROM IDAHO

Senator **McClure**. Thank you very much, Mr. Chairman. This bill would encourage solar and geothermal power production by removing the size limitation in PURPA for these kinds of facilities.

When PURPA was enacted in 1978, there was little expectation that it would foster the kinds and amounts of alternative power supplies it has. In large part, interest in the construction of PURPA facilities came about because of generous Federal tax credits and generous State public utility commissions who were willing to subsidize these facilities at ratepayers' expense.

Since 1978, however, both the Congress and the States have learned their lesson. The tax credits have been allowed to expire and State public utility commissions have generally acted more responsively, reigning in their avoided costs rates. Moreover, many States have instituted a competitive bidding program to price and select new power supplies. Without these developments, I could not have become a co-sponsor of this legislation.

My interest in this legislation, however, should not be taken as a sign that I wholeheartedly endorse unconstrained, wholesale power production. I could not, for example, support at this time removing the PURPA limitations on cogeneration facilities, nor can I yet support the thrust of the pending Public Utility Holding Company Act reform legislation. I am simply not yet convinced that PUHCA reform would be a good idea, but I am still willing to listen.

S. 2415 is only a modest and measured expansion of PURPA. It is for all of these reasons that I am willing to co-sponsor and support this legislation. I share with the Senator from New Mexico the desire to confirm the observations made in his statement. That is the purpose of the hearing, to determine what the facts are. And I will listen very carefully as we develop the facts to determine whether or not and in what manner and to what extent the Federal legislation should be directed to aid, at the margin, those forms of energy production which are worthy of the assistance that is needed in order to allow them to compete in the marketplace.

Thank you very much.

The **Chairman**. Thank you very much, Senator McClure. I might note that this is PUHCA reform for QFs, and maybe we ought to do PUHCA reform on this bill. That would get us a bigger crowd in here. [Laughter.]

Only kidding, only kidding. [Laughter.]

Mr. Davis, we are delighted to have you. Please proceed.

Senator **Domenici**. I just wish you good luck if you would like to do that, Mr. Chairman.

STATEMENT OF J. MICHAEL DAVIS, ASSISTANT SECRETARY, CONSERVATION AND RENEWABLE ENERGY, DEPARTMENT OF ENERGY, ACCOMPANIED BY ROBERT SAN MARTIN, DEPUTY ASSISTANT SECRETARY, UTILITY TECHNOLOGIES

Mr. **Davis**. Mr. Chairman, thank you, members of the Committee. I appreciate the opportunity to appear today to present the administration's position on S. 2415, the "Solar and Geothermal Power Production Incentives Act of 1990." I appear with my associate, Dr. Robert San Martin, who is the Deputy Assistant Secretary for Utility Technologies in my organization.

The bill has a timely and worthwhile objective, to encourage the efficient use of electric power supplies by removing the size limitations contained in the Public Utility and Regulatory Policy Act of 1978. We certainly agree that PURPA has demonstrated electric markets are flexible and responsive to financial incentives. We need to do what we can to make the most of those incentives.

The bill eliminates the 80 megawatt cap for solar and geothermal power. We agree that the cap needlessly restricts potential power supplies under PURPA. In our view, however, it is preferable to eliminate the 80 megawatt cap across the board for all energy sources covered by PURPA, rather than to do it selectively for specific technologies.

As part of the National Energy Strategy development process, we are examining the option of opening up competition for all energy technologies, rather than providing incentives for selected technologies. Our guiding principles are to pursue policies which promise efficient and reliable power supplies.

The power limitations, first 30 and then 80 megawatts, were imposed by PURPA in order to create a market for small, power production facilities and were based on renewable energy technologies. It was believed that renewable energy technologies would not exceed these limits. Today, however, renewable technology has advanced substantially since the time when PURPA was enacted, and the 80 megawatt cap on facility size, in some cases, does not allow facilities to be built large enough to maximize economies of scale. As a result, renewable energy facilities may be scaled down or not built at all.

Removing the size limitation is the right action to take at this time, because it will lead to additional competition among the firms and technologies competing to serve the utility power purchase market.

PURPA has been effective in allowing start up firms to enter the utility market without certain costly and time consuming regulatory requirements, and subsequently grow in size.

Luz International Limited is an excellent example. Having gained entry to the market through PURPA, Luz has built an increasingly cost-effective product based on solar thermal trough technology. It has 274 megawatts installed, and is serving the utility grid in Southern California. We believe firms like Luz can grow substantially by taking advantage of economies of scale. By simply going to a larger turbine, Luz estimates that it will be able to achieve a 15 percent cost reduction. Lifting the PURPA size limitations will allow Luz to pursue this new cost reduction target, and gain access to additional markets.

Removing the PURPA cap would likewise provide an incentive for other renewable energy technology firms to seek economies of scale and allow them to compete more effectively. Currently, the PURPA size limitations have the potential to constrain a variety of renewable energy technologies, from geothermal to municipal solid waste to wind. For example, a municipal solid waste plant in Virginia was recently constructed with 120 megawatt capacity, but plans to operate at 80 megawatts in order to qualify for PURPA treatment. Wind farms in California have also had to grapple with this issue.

S. 2415 would selectively favor solar and geothermal facilities. Rather than make such a distinction, we would prefer it if the legislation simply removed the cap for all renewable energy technologies, treatment that is already accorded by PURPA to cogeneration facilities. Removing the cap would clear the way for renewable energy to increase its growing contribution to our domestic energy supply with minimal impact on the environment.

Thank you very much. I would be pleased at this time to answer any questions the Committee might have.

The CHAIRMAN. Yes. Thank you very much, Mr. Davis.

Mr. Davis, with respect to the solar technology out in California, can you tell me whether or not the power provided during the sunny days, is that on peak or off peak?

Mr. DAVIS. I believe the majority of the power is produced for the utility at a point in time where they are responding to peak demand.

The CHAIRMAN. When are the peaks for power in California?

Mr. DAVIS. That would be in the early afternoon, early to late afternoon in terms of——

The CHAIRMAN. You mean all afternoon? All afternoon from 12 noon to what time?

Mr. DAVIS. Sir, I would defer to both the providers and consumers of that energy that you will hear from later, but I would think that—I do not have a particular utility demand curve in mind, but I would think that probably peaks around early to mid-afternoon. I could answer that question for the record with more detail.

[The information follows:]

During a typical summer day in California, peak demand occurs during the period noon to 6 P.M. During winter operation, peak demand occurs during a broader period, 8 A.M. to 9 P.M., Because summer air conditioning loads are greater than winter heating needs, summer peaks in California are significantly higher than winter peaks.

The CHAIRMAN. All right, because I think it is important to know whether or not, you know—PURPA has compulsion in it. I mean, these companies are not free to buy or not to buy. They must buy whether they want to or not, and they must do so at avoided costs, so I think it is important to know what kind of contribution they are making.

Now, if this bill passes, the following are some PURPA requirements or benefits, and I want to know whether you think we should eliminate the PURPA requirement of mandatory interconnect with utilities.

Mr. DAVIS. What we are prepared to address today, Mr. Chairman, is the cap, the size limit. PURPA is certainly a very complicated issue, and it is also a dynamic issue. There are a number of issues that need to be reviewed over time. I would expect that to continue. With respect to the cap, we would recommend that it be eliminated for all renewable technology.

The CHAIRMAN. Well, I understand that. You do not have a position on mandatory interconnect?

Mr. DAVIS. No, sir, I do not.

The CHAIRMAN. How about mandatory purchase at avoided cost rates?

Mr. DAVIS. I think the avoided cost approach is a legitimate approach and, in fact, should be self-policing.

The CHAIRMAN. Excuse me, would you repeat that?

Mr. DAVIS. I think the avoided cost approach is a legitimate approach, and I think it should be self-policing as long as there is careful definition of avoided costs. If you are dealing with a utility that needs additional power, that avoided cost at the margin would seem to be the most efficient way for them to acquire additional capacity. I think that is probably a healthy position.

The CHAIRMAN. Is that true if they must buy at off peak when they do not need the power?

Mr. DAVIS. I think again, each utility has a different characteristic, but if utility can strike a good deal in terms of adding to its capacity, whether it is peak capacity or other capacity at a favorable rate, then I would think they would probably want to do it.

The CHAIRMAN. Well, if they want to do it, why not let them do it, rather than compel them to do it?

Mr. DAVIS. Well, I think, again, across the board, that PURPA has certainly brought some competition and diversity into the electric utility market, and I think in that regard it has been successful. I think it has also given rise to the whole approach of competitive bidding, and I think that is also important to a market.

The CHAIRMAN. All right. How about the permission for these QFs to use 25 percent natural gas? Should they be permitted to continue that practice, no matter how large they are?

Mr. DAVIS. I would try and respond to that by saying that the majority of power production that has come on line through PURPA has actually been cogeneration facilities. The majority of that has been conventional fuel. About two thirds of the 27,000 megawatts you are talking about has actually come on with conventional fuels.

The relationship between renewables and fossil fuels, I think is important. A number of these plants make great sense as hybrids. In other words, a very good combination of fossil fuel, like say, natural gas, and solar thermal energy provides reliability and performance that the utility needs so that there is power available when they want it.

Exactly what that mix should be, exactly what the ratio should be, I am not prepared to address, but I clearly believe that there is a proper ratio. It would be nice, I guess, in a perfect world, if it was a completely free market, that a business operating such a plant would be free to decide what is the best ratio, but I am not prepared to suggest any change to the current ratio.

The CHAIRMAN. Well, you see the thing that bothers me about this is that we started with this bill with QFs and we were going to give, it seems to me, what was the first exemption, was it 30 megawatts or what was it? I think it was 30 megawatts.

And these were small people, and we were giving them two very important sets of advantages. First, they were to get the requirement of purchase. They had to buy, they had to mandatory interconnect, they had all this panoply of things, and then they had the lack of state regulation. They were not going to be subjected to all of that, because we wanted to help these small, little people.

And then we came along and we said, well, let us make that 80 megawatts, because 80 you have to have more economies of scale, and you can make a case for saying that there is a lot of compulsion to require them to buy a power that they do not need because it is on peak. You do not know the answer to the question, whether it is on peak or off peak, do you?

Mr. DAVIS. I think again, by a particular utility, that will vary, but the utility is a participant in this process of determining avoided costs, and I think——

The CHAIRMAN. Well, they may be a participant because they are required to be, but you have to buy this power, whether you want it or not. It seems to me that is the key, and now we are going to go from 80 megawatts, take the lid off and let them use 25 percent natural gas. I mean, the huge combines out there that will be using 25 percent natural gas, exempt from the Holding Company Act and all those other things. Why is that good? Is there some moral content in this energy that they are generating that makes it better energy than somebody else's energy?

Mr. DAVIS. Again, I would respond by saying that across all qualifying facilities, the majority of that power is being generated by fossil fuels, not renewable fuels. So I do not think you can separate out renewables as some kind of special treatment. I think that, in fact, is not the case.

The process of determining avoided cost, where you are involved with a utility that needs capacity, that utility is in a position to negotiate that avoided cost, that utility is in a position now, in a number of areas, to proceed with competitive bidding, which I think is a very positive process, where they can acquire the resources they need, whether it is base load or peaking, at what would seem to be their best advantage.

I think the overall effect has been to add diversity and competition, and our position is that we support that. You are talking about a very narrow aspect of the Act today.

The CHAIRMAN. Well, I mean it has been up to this point, using these small people, but I mean, we are talking about being very big. Why not exempt everyone from PUCA limitation?

Mr. DAVIS. The aspect of size limitations, I am prepared to address today. Other aspects I would have to respond to at a later time or for the record.

[The information follows:]

PURPA was enacted to promote energy efficiency and use of renewable energy resources. In order to accomplish these goals, small power producers (those with generating capacity of 80 MW or less) employing renewable energy technologies were granted an exemption from PUHCA requirements.

At this time, the Department of Energy proposes removal of this size limit only for renewable energy generating facilities, not for all generating facilities. The Department has not yet established a position on exempting all electric generating facilities from the requirements of PUHCA. We believe that removal of this size limit for renewables would further the goals of PURPA and recognize technological advancements in renewable energy applications that have rendered this limit less useful. Applying this recommendation to renewable energy facilities would encourage development of economically efficient renewable resources.

The CHAIRMAN. If you are able to compete on a cost basis with conventional resources, why is QF status necessary?

Mr. DAVIS. I think there is a number of issues in addition to having a market. If you are trying to penetrate a very, very regulated market, how do you do that? How do you do that with the new technology, whether it is a new natural gas technology or a new renewable technology? PURPA has largely addressed that issue, and I think it is now viewed as generally successful in addressing that issue. But that is quite a broader issue than the particular cap on capacity.

The CHAIRMAN. There is a present prohibition of more than 50 percent utility ownership on these QFs. Should we retain that limitation?

Mr. DAVIS. Mr. Chairman, again, I would have to respond for the record as an administration position on that.

[The information follows:]

Under FERC regulations implementing PURPA, if a utility owns more than 50% of the equity interest in a cogeneration or small power facility, that facility could not qualify as a QF under PURPA. This provision was intended to protect ratepayers from potential self-dealing by utilities as well as to protect QF developers from utility monopolization of the QF market.

The Department of Energy believes that this ownership cap has served a useful purpose. It has protected ratepayers from possible monopoly abuses and has contributed to the successful development of the QF industry. However, removal of this utility ownership limit raises many of the issues currently being debated in relation to efforts to amend PUHCA, e.g., ability of all potential participants to compete fairly in the generation market, ability of State commissions to protect ratepayers. The Department has not yet developed a position on modification of PUHCA, but is actively studying the issue. Until these issues are resolved, we believe that the present ownership restriction should remain.

The CHAIRMAN. Thank you.

Senator Domenici.

Senator DOMENICI. I just want to thank both of you for your support. As I understand it, you would like us to broaden the scope of S. 2415, but if we leave it as is, with reference to solar and geothermal, the administration, nonetheless, supports it. Is that correct?

Mr. DAVIS. Yes, sir. Our preference is that it be broadened.

Senator DOMENICI. I understand that, but could I ask you the question again? We think that the time has come to pass this bill. Obviously, we think we have the support to do it. I guess I would put it this way. If broadening it, as you have indicated, would increase the chances that we would leave it right where it is at 30 megawatts and 80 megawatts, would the administration prefer to have S. 2415 as is, or leave the 30 and 80 limitations on the solar and geothermal?

Mr. DAVIS. We actually think that broadening it would help ensure its passage.

Senator DOMENICI. I understand. The problem is, you do not vote. [Laughter.]

I am not sure you count, but you might, and I am not sure you have answered the question. [Laughter.]

Could I try again, and could you try again, or is that the best you can do? Let us assume that assumption on your part is erroneous. Would you prefer that we go ahead and take the cap off geothermal and solar and get something done in these two areas or not?

Mr. Davis. We would prefer, as a minimum, that happen.

Senator Domenici. Thank you very much.

That was a very, very difficult situation. [Laughter.]

Thank you very much, Mr. Chairman.

The Chairman. Senator McClure?

Senator McClure. If I understand, this is not the best bill that you can imagine, but you are not in opposition of the bill, and if it cannot be improved, you support this bill. Is that correct?

Mr. Davis. That is correct.

Senator McClure. Thank you. [Laughter.]

The Chairman. Mr. Davis—is that all you had?

Senator McClure. No, no. Just a couple of more. I want to follow up a little bit on some of the questions that Senator Johnston asked, because certainly this bill only touches the edges of utility policy and energy policy. And it is an important edge, and I do not want to minimize it. But I do want to understand the context in which the administration approaches this kind of legislation.

You have said that you support this bill, you would prefer that we have something else that was broader and you have identified that in your statement as being those renewable energy technologies identified in PURPA. Now, does the administration support going beyond that to the same kind of market aid to penetration or entry into the market towards other sources of energy other than the renewables identified in PURPA?

Mr. Davis. I am not prepared to provide an administration answer today, Senator.

Senator McClure. Okay. Because if I would understand it correctly, about all we have to do to accomplish what some people have decided they wish to do, and which I identify in some of the administration's statements and activities, is the restructuring of the electric utility industry, by way of making the entire industry more competitive and more subject to market forces.

Mr. Davis. That is correct.

Senator McClure. Now, would it not be a good way to get there by just simply removing the restriction on renewable energy, renewable energy sources, and removing the size restriction in PURPA, and would you not then have pretty much accomplished what perhaps is the administration's objective?

Mr. Davis. Yes. I would like to provide one example, if I might, though, why I think broadening has some merit. I touched on a facility down in Lorton. It is a municipal waste facility. It has actually got 120 megawatts of installed capacity, but will be operated at 80 megawatts, and I think it is a good combination of what to do with a growing problem. Right across the street from that facility there is another landfill. That landfill is busy venting methane to the environment, and the methane that is available in that landfill cannot be piped across the street to use in that facility because of restrictions such as these, and I do not think that makes any sense. I do not think that is what was intended, and I think the size limit as I have said, is the right thing to remove across the board. I do not know what it helps, so I do not see any large risk in removing it.

Senator McClure. I understand that point, but I would also say that, for myself, I have supported PURPA in the past, although I think there were some excesses under PURPA in the past, and still support the idea that maybe in public policy, we do not look just myopically at one factor, we look at several. And you mentioned the fact that we have got municipal waste disposal problems, and that maybe PURPA helped solve that municipal waste problem. That is not an energy objective, per se, or not wholly an energy objective, is it?

Mr. DAVIS. Well, it certainly is not wholly an energy objective, but if you can produce power from waste, and we believe there is substantial power there, and we believe that in parts of the country where we may have problems with electric capacity, it certainly should be examined and utilized to its fullest extent.

But as you note, properly, it is a very large issue. It is a very complicated issue. There are a number of factors, and it is certainly a dynamic issue, which means you all have to continue to look at it. This is one very specific effort, and we agree with it.

Senator MCCLURE. I agree with that, and I agree with trying to make public policy in terms of statutes that we pass. I am not quite the free marketeer that some people might believe I am, because I think government can be of some assistance at times, as well as some problem at times.

I supported the provision of the Pacific Northwest Power Act that said conservation gets a 10 percent kicker in its evaluation. I think that has been useful to us as a country, and useful to us in terms of moving the conservation ethic forward. That was not simply an energy question, that was mixed with other public objectives, just as dealing with municipal waste is another public objective.

If you put two sources of power side by side with an absolutely level playing field, the one with the lowest cost is the one that is going to win if your only objective is lowest cost. If, however, you have some other objective, then you should state that in public statute and permit that to be weighed in the choices as well. And I think that is what we are doing in PURPA. That is why we said in renewable energy, we want to give renewable energy a little bit better opportunity in the marketplace than it had prior to the passage of the Act.

If I understand you correctly, in the written statement that you presented to us today, you still believe that there is a reason for us to apply it to renewable energy. I was a little bit confused, and you rightfully said you were not prepared to answer that for the administration today. You wanted to submit an answer as to whether you want that restriction on renewable energy sources to be removed from the legislation, because that changes the whole basis for having passed the statute.

And then, if you remove the renewable energy sources from the PURPA and just say all energy sources, then it no longer is tilted towards renewable, and then it comes down to the other portion of motivation, which might be simply to restructure the electric utility industry without respect to the source of the energy. That is what is going through my mind as I listen to your responses and look at this legislation.

Would you like to see us amend PURPA to include hydro as a source?

Mr. DAVIS. Again, Senator McClure, I am not prepared to answer that question today.

Senator McCLURE. All right, because obviously, that has another set of public policy objectives, pluses, minuses and trade-offs.

We have had some experience now, under PURPA, and some comment made here today, as well as at other hearings with respect to the states' application of avoided costs calculations. And I think there is a general consensus across this country, I may be wrong, but I think there is a general consensus that some state regulatory utility commissions, early in the process, made avoided costs calculations that were too favorable to the new entrant in the market. Is that correct?

Mr. DAVIS. I believe there are examples where that is, indeed, the case.

Senator McCLURE. Do you believe at this time that those problems are behind us, or do you still see some such problems in some areas of the country?

Mr. DAVIS. I believe those problems are largely behind us.

Senator McCLURE. So there is no reason for us, at this time, to concern ourselves about the state regulatory process with respect to avoided cost calculations?

Mr. DAVIS. I do not think there is any need for concern.

Senator McCLURE. Mr. Chairman, I have no further questions at this time, thank you.

The CHAIRMAN. Mr. Davis, how would you know whether or not there is any problem or not?

Mr. DAVIS. Part of our activity is to keep track of state regulatory activities. We have a program that we call Integrated Resource Planning where we are working with a number of those state regulatory commissions to, hopefully, support their evaluation, their analysis and their assignment of value to a number of issues, other than just first cost. And there are a number of states that are starting to take steps in the direction that would encourage efficiency, that would also, possibly, give a small environmental offset, if you will, where renewable technology could qualify for those benefits. So, I think across the Nation, the states are going to wind up assigning value to a number of these issues, and with our efforts, we are trying to provide the analytic support to help them determine that value.

The CHAIRMAN. What I mean is this. Do you not find out if there is a problem by talking to utilities?

Mr. DAVIS. I think both the regulatory commissions and the utilities are important.

The CHAIRMAN. Well, I mean, the regulatory—the PUC is not going to tell you that they are using avoided cost to jawbone some utility into taking power that they do not want, are they?

Mr. DAVIS. They probably would not do that, no.

The CHAIRMAN. So, really your only source is utilities?

Mr. DAVIS. We have, maybe not the best contact, but growing contact with a number of utilities that are interested in these issues.

The CHAIRMAN. All right. Well, the point is this, it seems to me, and I do not know the answer to this, the extent to which the law is now being used to jawbone, but I think that you are not necessarily going to get the whole story, because there are very subtle ways that a PUC can jawbone a utility.

I mean, here is a big utility, and PUCs have this tremendous jurisdiction over them, and they come in and they say, well, by the way, we would like for you to consider hooking up this QF that burns walnut chips, walnut chips are very good, they produce a really fine kind of energy. And so they negotiate, and they sort of—the utility says, oh, we kind of get the picture, and utility goes along. How would you know whether that was happening or not?

Mr. DAVIS. Well, let us just say that I am certainly not the best person to answer that question. It is an important question, and there are a number of experts more knowledgeable than I am to answer it.

The CHAIRMAN. A particular example comes to mind, which I will not repeat here, where a PUC did that very thing to a utility and the utility ended up making the deal, and they figured, well, long-term relationship with this PUC, the PUC is very interested in it, it is good politics, and all that, and they went along with it. The PUC executive said, but boy it is really going to cost those consumers a lot over time. There is really no way for you to know whether that is taking place or not, is there?

Mr. DAVIS. No, there is not.

The CHAIRMAN. I tell you, I have some skepticism about these requirements of must purchase, and I know it is clearly not as bad as it was, clearly. But whether or not there is still some abuse here, I am not satisfied, and I would like to find out the answer to that.

Senator DOMENICI. I just had one question with reference to the Chairman's concern, aside from the issue of an end run around the basic utility holding company law, which is a different issue. Essentially, if we were not getting the price down dramatically where it is becoming competitive, then it would seem to me that the issue is a serious one.

But, as I understand it, and you correct me if I am wrong, a solar facility built in 1984 had electricity at life cost of 24 cents per kilowatt hour. I understand that by 1989, even under these very restrictive caps, it was down to eight. Is that the evidence you have?

Mr. DAVIS. Yes, sir, it is. That is correct.

Senator DOMENICI. Now, it seems to me that the whole issue centers around whether we are apt to do substantially better on price, since many of the utility rate-making groups are going competitive and asking for bids, if we want to promote this kind of energy for all different reasons, and apparently you are here because you want renewables given a maximum opportunity in this regulated environment. Then it seems to me we have to take a cap off if we want to maximize the opportunity to get to six cents, which people are saying we ought to get to.

I guess my question is, is it not more apt to happen, that is, that it would get truly competitive, and get down as low as six if we take the cap off, just speaking of solar now? Is that not the case with reference to both the companies, the consumers and the ratemaking utilities?

Mr. DAVIS. It is absolutely the case, and I think it steps in the right direction of solving the concern that the Chairman has.

Senator DOMENICI. It appears to me, and that is why I asked the question, the ultimate concern that the Chairman has is that you would force the purchase of power on the utilities through these very heavily subsidized contracts. From what I am finding out, we are more apt to perpetuate that and minimize the use of, at least these two, if we do not take the cap off than if we took the cap off.

Mr. DAVIS. Yes, sir.

Senator DOMENICI. I thank you.

Senator MCCLURE. Mr. Chairman, I do not know whether this committee is going to want to take the cap off on anything other than the two technologies that are mentioned here or not. My perception would be they probably will not, but it has been your suggestion that we do broaden it to all renewable energy sources. And that gets us back——

The CHAIRMAN. Why not all clean energy?

Senator MCCLURE. That gets us kind of back into the question that the Senator from Louisiana, the Chairman of the Committee was mentioning a moment ago, and one of the things that has perplexed many of us under PURPA, and that is whether or not there should be a need for the power before they can be forced to purchase. If we look only at the relatively more limited areas, small generators that we have had under PURPA up until this time, geothermal and solar that are specified under this bill, but if we go further and say, all renewable energy sources, then you may get into quantities of energy that begin to back out power generation facilities on utility systems that have no need for power now.

Somebody builds a new qualifying facility. Go to them and they say, you have got to buy it, and they back out some generating capacity they have already. Is that not a possibility if you make the application of PURPA too broad?

Mr. DAVIS. I do not think it is, because again, the self-policing action, if you will, of avoided costs. If a utility really is in a situation where they do not need additional power, and that is clearly understood between the utility and the associated regulatory commission, and it is hard to imagine that avoided cost would allow the purchase of any additional power supplies.

Senator MCCLURE. Avoided cost does not talk about existing supplies. It talks about alternative new supplies.

Mr. DAVIS. Yes, sir, that is correct. But if you are trying to operate a facility and justify building it and selling the power at an avoided cost rate, and that cost rate is so low that in fact, it is not possible, then I cannot imagine that anybody would proceed.

Senator MCCLURE. But the avoided cost has nothing to do with the existing supply, either the form, substance or cost.

Mr. DAVIS. I believe it does have something to do with the existing position of the utility. It absolutely does. What avoided cost is, in my mind, supposed to get at is the utility, whether it has a need for additional capacity or a utility that does not have a need for additional capacity.

Senator MCCLURE. That is not in the statute today. That may be in your mind, but it is not in the law. Do you think that is happening, even though it is not expressed in the law?

Mr. **Davis**. Yes, sir, I do. I think that is in the negotiation process, that it is, in fact, taking place. And I think that has indeed been helped by the regulatory process.

Senator **McClure**. Does the regulatory process at any point in the regulations spell out the need for power as part of the basis for the calculation on avoided costs?

Mr. **Davis**. No, it does not.

Senator **McClure**. Well, very honestly, Mr. Chairman, that is one I would want to pursue a little further, particularly if the committee has any disposition to broaden the bill beyond the current status of the bill.

Thank you.

The **Chairman**. Thank you very much, Mr. Davis.

Mr. **Davis**. Thank you, Mr. Chairman.

The **Chairman**. Next, we have a panel composed of James C. Bazor, Chief Operating Officer of Luz International from Los Angeles; Scott Sklar, Executive Director of Solar Energy Industries Association in Arlington; and Robert T. Boyd, Director of Regulatory Affairs of U.S. Windpower, Incorporated from Livermore, California.

Gentlemen, welcome, and we will begin with Mr. Bazor.

STATEMENT OF JAMES BAZOR, CHIEF OPERATING OFFICER, LUZ INTERNATIONAL, LIMITED

Mr. **Bazor**. Thank you, Mr. Chairman. I am going to summarize my testimony, the written testimony and ask that it be entered into the record.

Mr. Chairman and members of the committee, I am James Bazor, Chief Operating Officer of Luz International, Limited. We are a California corporation that currently produces 274 megawatts of solar electricity. I might add that last year we completed our one-billionth kilowatt hour of solar production; 800 million of those hours were peak capacity. So, to answer the Chairman's question, we produce our power predominately during the peak periods when the utilities need it the most.

My background is basically in the construction industry. Included in that background is about 27 years in the power construction industry. During that length of time I have been involved in industrial generation, nuclear power plants, fossil fuel power plants and just about the whole spectrum. Based on that experience, I am cautiously optimistic about the future of solar energy, the reason for that being twofold. One is the construction period of relatively short, about 14 to 18 months after conception of a project. Another thing, that is basically non-polluting, and another reason is that we have been able to bring our costs down in five years, from 24 cents to eight cents a kilowatt hour. That is over the life cycle of the project.

Now, we thought back in 1984 that eight cents would be a good number, but after you get out here looking at the market right now, five and six cents is a good number to stay alive and to be competitive in the marketplace. I have heard all the discussions about PURPA. We are going to have to get our cost down. This is dollars and cents things to us, to be competitive, about what we come under.

So, I need to explain a little bit about how we got from 24 cents to eight cents, to tell you how we are going to get from eight to six cents. Our first unit, SEGS-I—SEGS, incidentally is Solar Electric Generating Systems—SEGS-I was a 14 megawatt unit and we put on line for 24 cents kilowatt hours. Granted, we had 40 to 50 percent subsidies, we had a good power purchase agreement. We had everything going for us at that time. Of course, that is when everybody thought oil was going to get to $100 a barrel one day, too, but was mistaken.

We could see some of the trends, and the next project we built, SEGS-II, we upscaled it to 30 megawatts, which was allowable under the law at that time. That allowed us to reduce the cost of our electricity to 17 cents a kilowatt hour. Now, for the next five units we built—they were all 30 megawatt units, a total of six 30 megawatt units. Just through R&D and technology development, we brought that cost down from 17 cents to 11 cents on the last 30 megawatt unit we put in service.

I might add that we put just about every dollar of our retained earnings back into R&D to get that cost down. Now, granted, we were incentivized by survival, but we did plow that R&D money back into—our retainer back into R&D. And as a result, we were successful in bringing it down.

But along the way, all these good subsidies and everything were diminishing, too. We got to 1989 and we found out we had 10 percent investment tax credits left. So they diminished from 40 percent to about 10 percent. That same time frame, we brought our cost down 67 percent.

Now, thanks to the legislation, sir, that I think you sponsored, we were again allowed on SEGS VIII, the last unit we put in, to upsize it from 30 to 80 megawatts. Quite simply, had we not done that—that is how we got it down to eight cents—had we not done that, we would not have been in business now, because of the deflating gas prices and everything and losing the subsidies we had. So, I will not argue that we did not have subsidies along the way.

What I will argue is that they were put to good use. what I will argue is that not only did we have outside subsidies, we subsidized ourselves by putting our retained earnings back into this technology. We have not paid our investors one thin dime in 10 years. Now how long that is going to last is anybody's guess.

Now, instead of belaboring that point, I would like to move on to how we are going to get from eight cents to six cents, and quite frankly, out in the competitive marketplace, I think we are going to have to be closer to five cents. We have got some contracts now that are going to last about two or three more years that we are working on, trying to make them work. But we know that to get any more contracts, it is going to be on a dollars and cents basis. That is what we have found out so far. So, we have got to hit that five or six cents.

Every time we have upscaled, we have been able to reduce costs, just on that, but we are not going to get all the way just upscaling. We are going to have to pump a heck of a lot of money back into R&D to get this other two-and-a-half or three cents out. The easy part is over. The obvious part of approving our technology is behind us. We are down to the hard part now, of reducing the cost of our electricity. We are confident that we can make it because of our track record, and the qualified people we have got working on this thing. But to do that, we have got to be allowed to upscale along with plowing our money back into R&D.

When you upscale, basically, say, for an example, from a 30 megawatt power block to an 80 megawatt power block, an 80 megawatt power block almost produces three times more than a 30 megawatt, but the cost is only about twice—the capital cost is only about twice as much. We also save in labor costs because it takes about the same number of people to operate an 80 megawatt unit as it does a 30 megawatt unit.

To us, this legislation, without it, we have a very gut-wrenching decision to make. Right now, we are plowing money into our technology, trying to get towards that five cents to six cents per kilowatt hour. Now, we know if we cannot upscale, we are not going to make it, because we have looked at this technology. We have been hammering at this for five years now, done a pretty good job. But without upscaling, we are not going to make it.

Now, the decision is, do you recommend to your board that we keep putting in this money to try to get down to the five cents and bet on the come that something is going to happen where we can build a larger unit sometime during that time, and get down to five or six cents? Or do you back off of your R&D. Quite honestly, we do not want to back off of our R&D. We think we can make it, coupled with this size escalation.

And then, when we get there, nothing will please me any more to tell all you people, we do not need anything. We do not need any of your help. Then, we do not have to argue about who is getting this and who is getting that. All we are asking to is let the market and the technology dictate the size of our projects so that we do not have to ask anybody for anything.

Now, I think that the passage of 2415 is good economic policy, it is good environmental policy and it is good energy policy.

Thank you, sir.

[The prepared statement of Mr. Bazor follows:]

Testimony of James Bazor
Chief Operating Officer
Luz International Limited

Senate Committee on Energy and Natural Resources
Hearings on S. 2415

May 15, 1990

Mr. Chairman and members of the Committee, my name is Jim Bazor and I am the Chief Operating Officer of Luz International Limited, a California corporation. Since 1984 Luz has placed in service 274 megawatts of reliable utility grade solar electric generating capacity, demonstrating that current solar technology can meet utility needs.

My own background prior to joining Luz included 27 years as an engineer and executive in the power plant construction industry. During that time I was personally responsible for fossil fuel and nuclear power plants as well as renewable energy projects. Based on my combined experience, I am very optimistic about the potential of solar electric generation in the United States. In particular, modular design and environmental advantages will make solar facilities an increasingly attractive utility option, particularly for peak power supply.

However, current law requires change for the full potential of solar energy to be unlocked. Specifically, scale limitations under the PURPA program increasingly, and inappropriately, constrain the development of competitive and cost effective solar facilities.

The marketplace for non-utility generation has become extremely competitive, as the members of this Committee well know. Third party generators can only secure contracts if they are able to meet competitive pricing terms. Long term standard offer contracts with favorable pricing provisions, essential to the financing of the first solar projects, are no longer available. In short, solar facilities must be price competitive without the benefit of rate subsidies, and the current size limit under PURPA makes it very difficult to participate in this new environment.

The Luz Solar Electric Generating System, what we call SEGS technology, has proven that solar power plants are able to meet utility industry standards for reliability. As a measure of this success, we are pleased that the utility which purchases the output of our systems has praised the quality, load tracking ability, and performance of our power plants.

Reliably meeting utility load requirements, however, is only half of our challenge. Producing power at a competitive price is equally critical. While project economics have improved dramatically in a very short period of time, it has been difficult to catch the moving target we are chasing.

In 1984 the generating costs at SEGS I, our first power plant, were 24 cents per kilowatt hour on a lifecycle basis. At that time, to become fully competitive with fossil fuel generation, our goal was to reduce generating costs to 8 cents per kilowatt hour. In five years we accomplished that goal, but as a result of fossil fuel price fluctuations, the target had moved further away from us. By 1989, the new target had become 6 cents.

We can hit the 6 cent target as well. But we know from our experience at reducing costs in the past, this target can only be reached if we are permitted to build larger facilities that benefit from further economies of scale.

To hit the 8 cent target in 1989 required a 67 percent reduction in costs over five years. Two factors were critical to realizing this objective: an intensive in-house research and development program to improve performance and reduce the cost of virtually all system components; and federal legislation allowing us to increase in size from 30 to 80 megawatts.

Ploughing all of our earnings into privately funded R&D has enabled us to achieve significant technical improvements. The third generation of SEGS solar field technology operates more efficiently and at a higher temperature, enabling us to convert sunlight into electricity at a lower price. These research and development advances made it possible to reduce costs from 24 cents to 12 cents per kilowatt hour, which is the cost of generating power at our last two 30 megawatt plants.

To get from 12 cents to 8 cents, however, research and development alone was not enough. Legislation allowing solar facilities to increase in size to 80 megawatts was essential for us to realize these additional savings. Our experience building SEGS VIII, our most recent power plant, shows that economies of scale associated with building and operating an 80 megawatt facility resulted in a 25 percent reduction in generating costs.

For solar energy to become fully competitive with fossil fuel alternatives under current market conditions, we must now reduce costs by an additional 2 cents per kilowatt hour, another 25 percent reduction in generating costs. And we believe that this goal is also achievable if we are once again able to combine research and development with economies of scale.

Building facilities larger than 80 megawatts will result in two principal savings: lower power block capital costs and lower operating and maintenance costs per megawatt installed.

Unlike a conventional power plant, our facilities have very significant capital requirements for a solar field. The only reason that we can be competitive on a lifecycle basis is that the solar energy which fuels our power plants is free and non-polluting, reducing operating expenses.

We are like other conventional power plants, however, to the extent that the cost of our power block does not increase proportionately with size. For example, an 80 megawatt power block is approximately twice the cost of a 30 megawatt power block, but it has nearly three times the gross output. Similarly, a 200 megawatt power block is less than twice the cost of an 80 megawatt power block.

The other principal savings, in operations and maintenance costs, result from the fact that the size of a crew needed to operate a solar power plant does not increase proportionately with size. The same number of personnel are required to operate computer terminals and other equipment used to monitor plant operations regardless of whether a facility is 30, 80, 200 megawatts, or larger.

The Luz experience underscores the critical importance of this size change legislation and illustrates that there is virtually no risk that this legislation will burden either utilities or their ratepayers with higher costs. The proposed legislation will simply allow market and technological factors, rather than a statutory size limit, to determine the most economic size for a solar facility. Moreover, this legislation will allow renewable technologies to compete on a level playing field with fossil fuel cogeneration under PURPA.

In 1984, with lifecycle costs of 24 cents per kilowatt hour, SEGS I could only be financed because of favorable federal and state policies which are no longer available to us: state and federal tax credits of 25 percent each and a thirty year California Standard Offer Number Four power purchase agreement with fixed energy prices for the first ten years based on then current assumptions that fossil fuel prices would continue to escalate. When solar technology was still unproven, this combination of benefits was necessary to support private financing for a high risk project with high costs per kilowatt hour.

Current projects must be economic without the benefit of these tax and rate subsidies. SEGS VIII, placed in service in 1989, generates power at a cost of only 8 cents per kilowatt hour, but SEGS VIII was also economically marginal because of the change to a more stringent California Standard Offer Number Two contract, based on a quarterly adjusted index of the purchasing utility's actual gas costs. Moreover, SEGS VIII was eligible for only a 10 percent tax credit.

These current contracts offer no special subsidy either because we are qualifying facilities or because we are an environmentally attractive alternative. Given the current price of gas, and the persistent high cost of capital, the SEGS projects continue to have very thin economic margins. Dramatic progress has been essential simply for these projects to remain viable.

Looking ahead to future projects, we see a market with increasing competition, where environmental benefits may or may not be reflected in the price we are paid. This leads us to the inevitable conclusion that our strategy must be to reduce costs and compete for contracts on an economic basis.

In every state where we are looking at possible project development -- and indeed all over the country -- utilities and state regulators are developing either competitive bidding systems or guidelines for competitive negotiations.

In Nevada, for example, we are actively competing for a contract to meet Nevada Power Company's need for new generating capacity. In these negotiations, we are given no advantage either for being a QF or for being environmentally attractive. In fact, both fossil fuel QF cogeneration projects and non-QF fossil fuel projects have a competitive advantage because they are free to build more economically sized facilities. In contrast, PURPA's size and fossil fuel use restrictions for renewable technologies are making it very difficult for solar facilities to meet Nevada Power's requirements, even though the insolation in Nevada is excellent.

We do not believe that a small company with a new technology can absorb the regulatory risk associated with developing a non-QF independent power project under current law. Consequently, maintaining QF status is critical and we are making every effort to accommodate Nevada Power's requirements as a QF. But we know that the economics of an 80 megawatt facility are not likely to work, and that the only real chance for successful Nevada projects is to build larger facilities which incorporate our latest technological improvements.

In other high insolation states, such as California, New Mexico, Colorado, Arizona, Texas, Utah and Hawaii, future contracts will be won or lost based on a formal or informal bidding system, where the right to sell power will only be available to a project which can sell power on the most competitive basis.

PURPA today defines a playing field where market mechanisms determine the price a utility will pay for power. PURPA's mandatory purchase requirements offer no subsidy or preference for QFs when contracts are awarded through competitive procedures where QFs and non-QFs are both participating.

For Luz as a company, our thin economic margin translates into very low retained earnings, and a need to continue to fully reinvest those earnings into research and development simply to remain in business. After a decade of operations, Luz has never paid a penny of dividends to its stockholders.

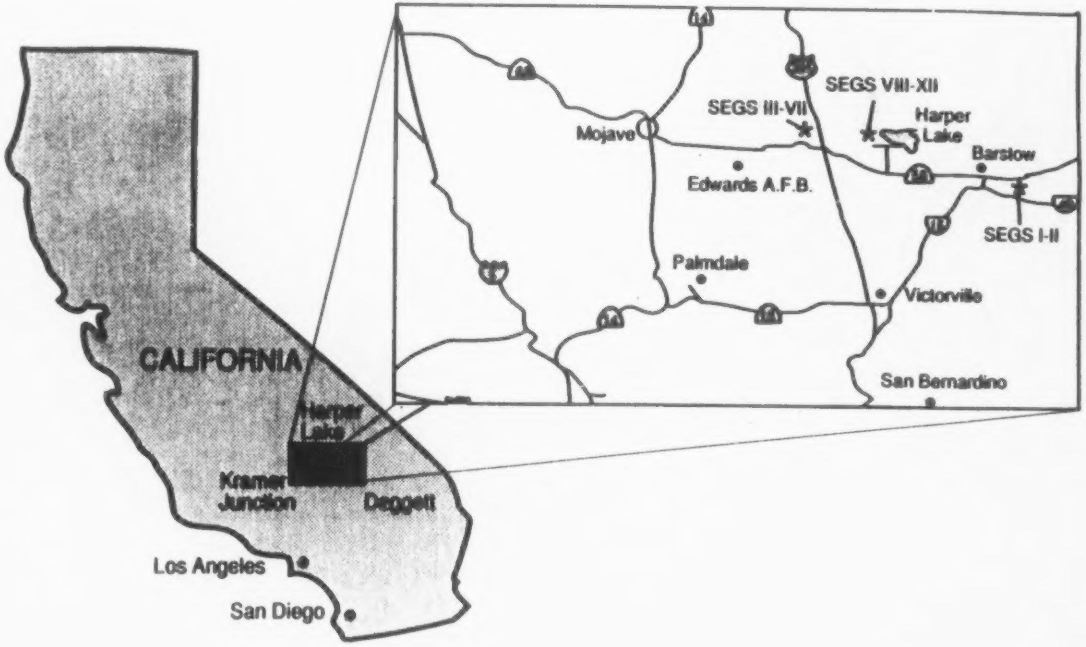
Our challenge is to continue financing, building and selling projects, so that this technology can stay in production until external market conditions -- higher fossil fuel prices and lower interest rates, together with further technological improvements, make solar technology fully price competitive, which today means reducing generating costs to 6 cents per kilowatt hour.

We are optimistic that in the foreseeable future, solar facilities, if permitted to gain experience at an optimal economic size, will become the power plant of choice for utilities in the southwest with a need for new capacity. We believe this judgment will be driven by both economic and environmental considerations. What we are seeking is a bridge that will enable solar technology to make the final transition necessary to become fully competitive.

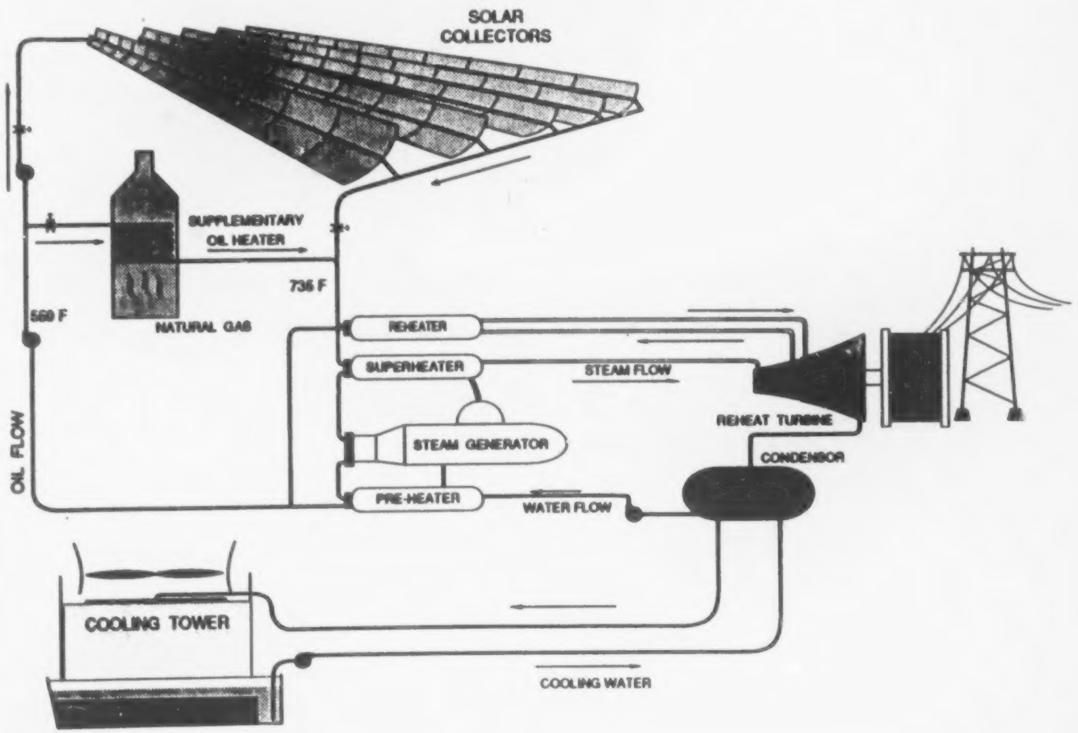
To reach this goal it is critical that we be permitted to build larger facilities with further economies of scale. Because these savings arise from increased efficiency and productivity, this change in law offers utilities and their customers the prospect of the cleanest possible generation at the lowest possible price. We think this is good economic policy, good energy policy and good environmental policy.

Thank you very much.

Map of Kramer, Daggett and Harper Lake

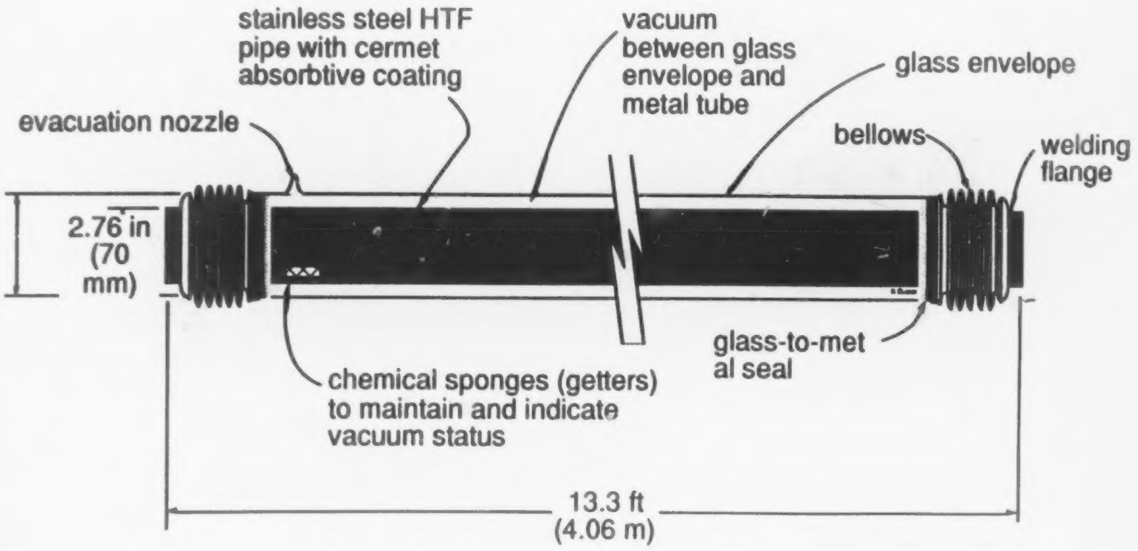

CALIFORNIA
Harper Lake
Kramer Junction
Daggett
Los Angeles
San Diego
Mojave
SEGS III-VII
SEGS VIII-XII
Harper Lake
Barstow
Edwards A.F.B.
SEGS I-II
Palmdale
Victorville
San Bernardino

SEGS VIII - System Flow Chart


SOLAR
COLLECTORS
SUPPLEMENTARY
OIL HEATER
736 F
560 F
NATURAL GAS
OIL FLOW
REHEATER
SUPERHEATER
STEAM GENERATOR
PRE-HEATER
STEAM FLOW
WATER FLOW
REHEAT TURBINE
CONDENSOR
COOLING TOWER
COOLING WATER

LUZ International Limited

Heat Collection Element


stainless steel HTF pipe with cermet absorbtive coating
vacuum between glass envelope and metal tube
glass envelope
evacuation nozzle
bellows
welding flange
2.76 in (70 mm)
glass-to-metal seal
chemical sponges (getters) to maintain and indicate vacuum status
13.3 ft (4.06 m)

LUZ International Limited

CHARACTERISTICS OF SEGS I-VIII

Plant	Placed in Service	Turbine Capacity	Solar Field		Turbine Cycle Efficiency		Annual Output (MWh)
			Temp (F°)	Size (square) (meters)	Solar	Boiler	
SEGS I	1984	13.8 MW	585	82,960	29.4	--	30,100
SEGS II	1985	30 MW	600	188,987	29.4	37.3	80,500
SEGS III	1986	30 MW	660	230,300	30.6	37.4	92,780
SEGS IV	1986	30 MW	660	230,300	30.6	37.4	92,780
SEGS V	1987	30 MW	660	233,120	30.6	37.4	91,820
SEGS VI	1988	30 MW	735	188,000	37.5	39.5	90,850
SEGS VII	1988	30 MW	735	194,280	37.5	39.5	92,646
SEGS VIII	1989	80 MW	735	464,340	37.5	37.6	252,750

HISTORY OF LUZ CONTRACTS

Pioneer Contracts	Size	Cost/kwh*
SEGS I	13.5MW	.24¢
SEGS II	30MW	.17¢
California Standard Offer 4		
SEGS III	30MW	.13¢
SEGS IV	30MW	.13¢
SEGS V	30MW	.12¢
SEGS VI	30MW	.11¢
SEGS VII	30MW	.11¢
California Standard Offer 2		
SEGS VIII	80MW	.8¢
SEGS IX	80MW	.8¢
SEGS X	80MW	.8¢
SEGS XI	80MW	.8¢
SEGS XII	80MW	.8¢
Competitive Bidding Target		5.6¢

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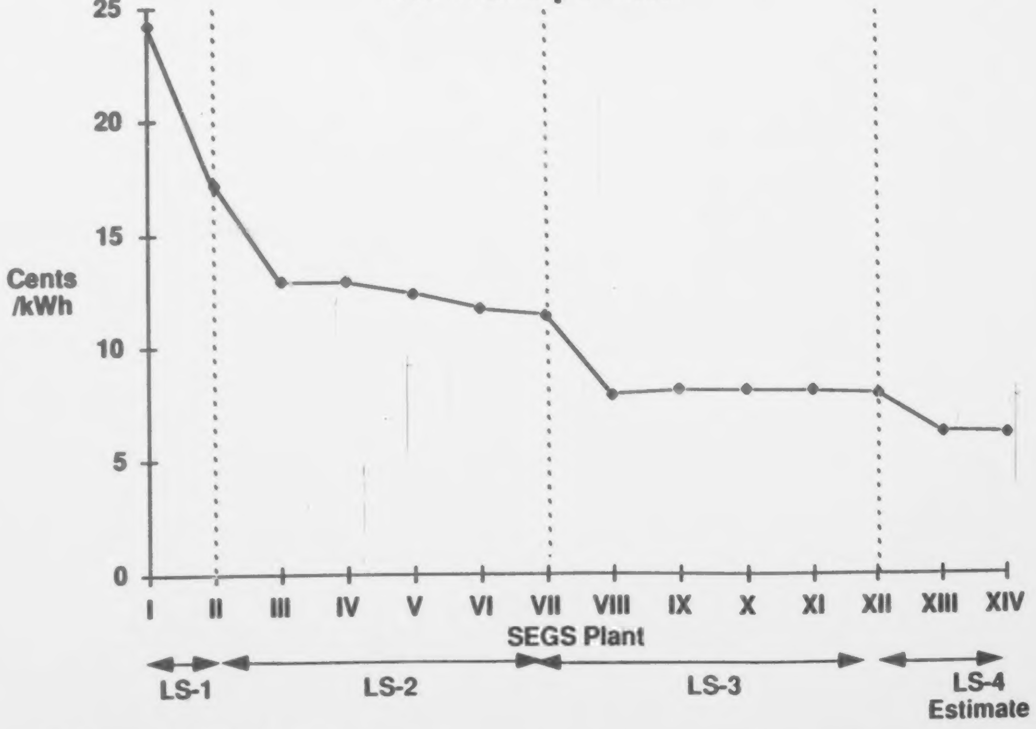
* Lifecycle basis

Levelized Cost of Power From SEGS

1988 Cents per kWh



LUZ International Limited

The CHAIRMAN. Thank you very much.

Next, Mr. Sklar.

STATEMENT OF SCOTT SKLAR, EXECUTIVE DIRECTOR, SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. SKLAR. Hello, Senator. Good to be back before you.

The Solar Energy Industries Association is the national trade groups for both the solar, thermal and photovoltaic industry, and manufacturers and component suppliers. And aside from my written comments, I have basically five points to make before this committee.

One, as you all know, very clearly, this solar industry is very young. Most of the industry was not around at the 1973 oil embargo. Most of the industry, 90 percent, started around 1978, are essentially just 12 years old. There is always a question up here of where we have come in 12 years. Well, yes, with a combination of R&D, tax incentives and some regulatory incentives, photovoltaic costs have dropped 10-fold, solar steam costs or thermal costs, at least over the last five years, have dropped three-fold, and that is a pretty impressive gain. We have a way to get commercialized with that anyhow, but it is near and we can see the light at the end of the tunnel.

The second issue is that for new, emerging technology you need steady, clear, consistent policies to the marketplace, and changes in proposing anything in terms of mandatory buys or anything else, gets people nervous. Right now, what we are looking for is a minor, what I perceive as a minor technical correction to an existing law so that the same market signals are clear, so that the companies like Luz and others can still retain the confidence of investors who have a vision to get this technology to the marketplace and will invest their own R&D in getting there. That has been consistent throughout the industry.

The third point is, while the Luz technology on the solar side is in the forefront, there is a wide range of other technologies that are coming right behind them.

The dish engine work that Cummings, John Deere and Westinghouse will be commercializing in 1992, you will see this technology in the marketplace, albeit smaller than 80 megawatts, but in the later 1990s they will be——

The CHAIRMAN. What engine?

Mr. SKLAR. The dish engine, external combustion engines to dishes, they are being commercialized by those three companies in support of the DOE program, and then obviously, photovoltaics in the late 1990s will come out of the remote market and really into the peak power market. So, there is an industry out there that is perceiving the need for this kind of support, because it will track the kind of capital to keep us in the forefront of the technology.

The fourth point I have is that we in the United States are not the only people in this technology, and that our international competitors on utility scale applications are not standing by. Germany is doing a full court press in terms of photovoltaic utility scale applications. Spain and the economic——

The CHAIRMAN. In terms of what?

Mr. **Sklar**. Photovoltaic utility scale applications. They will have 10 megawatt size peak power plants in photovoltaics in Germany over the next two years. They are in an enhanced development stage in photovoltaic utility scale. The same is true with the European economic community in terms of solar steam.

My point here is that one of the reasons the United States has led in the technology and controls the market share, is that you in the Congress has had the sensitivity that you have to build a market here to get out industry strong enough and the experience to compete in a worldwide market.

The last point I have to make is really that this needs to be perceived—the size change—as a technical correction. 30 megawatts, 80 megawatts were really arbitrary. In 1978, you were all involved in this legislation. There was no perception that solar technology would ever go above 30 megawatts. It was hard to believe at the time, and when we came to the Congress to go to 80 megawatts to make solar consistent with geothermal, again, it was an arbitrary level, because geothermal already had 80 megawatts, and again, it was perceived that, boy, that is pretty big.

The fact of the matter is, the marketplace will determine the correct size if this technology, and by being able to extend or increase that size, these companies will lower their costs and the whole goal of this process was to allow this industry to lower our costs and able to stand on our own two feet, and you will be able to do that and feel good about that.

So, I would like to thank the Committee for considering a hearing on this issue. I think it is important. I think it is important that it be timely. Thank you very much.

[The prepared statement of Mr. Sklar follows:]

SEIA

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FAX: (703) 527-2833

TESTIMONY

by

Scott Sklar
Executive Director
Solar Energy Industries Association

before

Senate Committee on Energy
& Natural Resources
(S. 2415)

May 15, 1990
Washington, D.C.

INTRODUCTION

The Solar Energy Industries Association (SEIA), the national trade association for the solar thermal and photovoltaic manufacturers and component suppliers, strongly supports a needed technical correction for the equal treatment of solar and renewable energy independent power production facilities. Extending the PURPA limit beyond the 80 MW facilities will insure fair and consistent treatment of solar energy sources through PURPA.

The U.S. solar industry must be assured of access to cost-effective markets if we are to maintain our technological preeminence and compete effectively in the international markets. PURPA remains one of the few means left for the development of solar and renewable energy domestically. Equal treatment of solar electric technologies is important using the PURPA vehicle to enhance the competitiveness of utility-interconnected solar facilities. Proposed legislation to extend PURPA limits achieves that end simply and effectively.

PHOTOVOLTAICS

The U.S. photovoltaic (PV) industry is facing strong international competition. The U.S. world market share has dwindled over the last six years from 80 to 50 percent. Over 60 percent of the PV industry's annual sales are for export. Currently the industry has approximately 14 MW in the utility sector. Photovoltaics, which convert sunlight directly into electricity, have had their costs reduced tenfold over the last decade.

Over the next decade, photovoltaics will become a choice technology for utility peak power generation due to its modularity and low cost operations and maintenance. PURPA is of supreme importance to further domestic development of utility-grade use of photovoltaics.

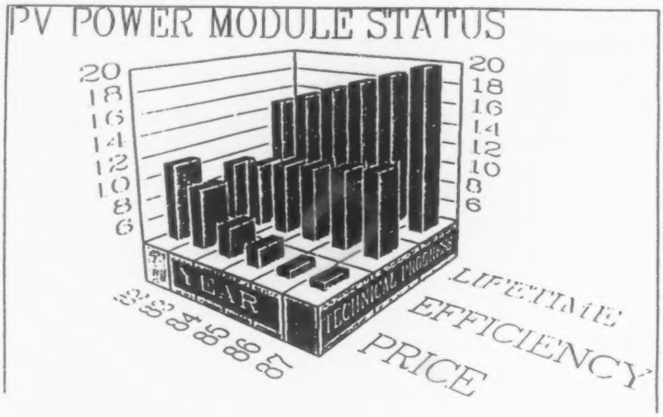
For the past several years, much of the PV industry has worked under the leadership of DOE and EPRI toward the mid-1990's commercialization of PV power systems for utility use. Many utilities are currently conducting investigations into new generation sources for the mid-to-late 1990's. PVUSA complements the ongoing PV cell and module research and development programs at DOE, EPRI, universities and other entities by providing an opportunity for utilities to field test a wide range of PV technologies and different Balance-of-System (BOS) configurations in a utility setting.

Photovoltaics for Utility Scale Applications (PVUSA) is a national, public-private partnership demonstration project to assess the viability of utility scale photovoltaic (PV) generating systems. By mid-1991, PVUSA is scheduled to have 12 PV technologies under test totaling about 1 MW peak AC output;

the largest will be a 400 kW array. The main test site is at Davis, California.

Phase 1 of PVUSA is deploying and evaluating a dozen PV technologies at the Davis site. Nine pilot systems, each about 20 kW, of Emerging Module Technologies (EMT) are being installed. These are systems literally emerging from the laboratory, which show promise of meeting energy cost goals that indicate a probable field test life of more than 5 years, and represent a substantial technical/cost improvement over similar systems already deployed. Utility Scalable (US) systems of 200 and 400 kW each also are being installed at Davis. These are systems judged to have the potential to produce low-cost energy and also meet maintenance, power quality, high reliability and extended lifetime requirements for utility application. Additional, utility hosted segments of US-1 technologies also will be deployed at the sites of participating utilities, in nominal ratings of 25 or 50 kW. Utilities will utilize a series of modular photovoltaic systems in the 500 kW - 5 MW range to provide power in the future. Photovoltaics will need a size change extension in the long-term so the industry can reach certain economies-of-scale to be further cost-effective.

PHOTOVOLTAICS: EFFICIENCY, RELIABILITY & COST REDUCTIONS



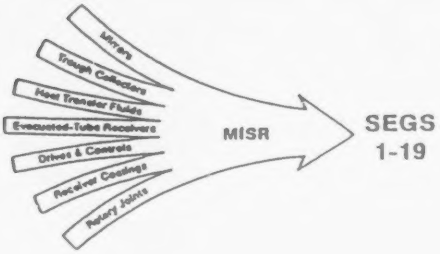
SOLAR THERMAL POWER

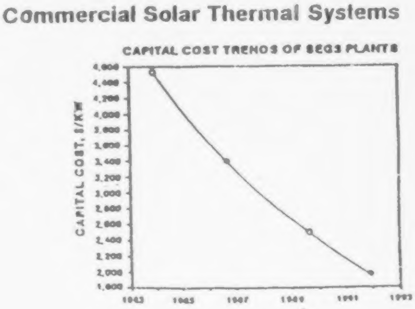
The conversion of sunlight to produce steam to turn an electrical generator now produces more than 270 MW in the United States. Large-scale solar thermal facilities are prime choices for utility peak power in the southwestern United States.

Although solar thermal power plants are commercial, it is imperative that an increase in plant size be permitted to lower costs of production. Utility-scale facilities must be increased beyond the 80 MW limitation to take advantage of the inherent economies-of-scale. By furthering the size of solar thermal power plants, the ensuing cost reductions would expand the potential of this technology over the full southwest region.

The U.S. government should be aggressive in broadening the use of technology it was instrumental in commercializing. The trough technology now used, and the emerging dish/engine technologies, will provide pollution-free electricity at competitive costs especially if economies-of-scale can be realized.

SOLAR THERMAL POWER: LOWERING CAPITAL COST TRENDS





INDEPENDENT POWER AND NATIONAL SECURITY

Solar and renewable energy represents an ever growing resource base for electric power production. According to The Council for Renewable Energy Education (CREE), over 7500MW are produced from the following resources: anaerobic digestion, geothermal, landfill gas, municipal solid waste, photovoltaic (PV), solar thermal power, wind, wood/ag waste.

Over 7460 MW of electric capacity can be attributed directly to domestic renewable resources. This capacity can double within the next five years, lessening petroleum imports, acid rain, carbon dioxide emissions, and high-cost large-scale central power plants.

On November 9, 1978, the Public Utility Regulatory Policies Act (PURPA) was signed along with four other national energy initiatives designed to combat the energy crises. Section 210 of PURPA's Title II, 92 Stat. 3144, 16 U.S.C. S824a-3 was created to encourage the development of cogeneration and small power production facilities. Congress believed that increased use of renewable sources of energy would reduce the demand for petroleum, an important goal for the United States energy security and long term economic security.

The solar industries of the United States support PURPA in regard to independent power development of solar technologies. SEIA urges the Committee to increase the PURPA limit to promote solar energy development.

CONCLUSION

The direct conversion of sunlight to electricity through photovoltaics and the concentration of sunlight for thermal electric generation will increase in the United States if PURPA limitations are increased. This goal deserves passage by the U.S. Congress in a timely manner.

Passage of an extension will help maintain U.S. solar predominance in the marketplace by insuring a domestic market for these technologies. Such policies will increase the growth of the U.S. solar industries, offset petroleum imports, and positively assist the U.S. trade deficit.

U.S. imports of petroleum have exceeded 50 percent and these imports represent one of the single largest components of the U.S. trade deficit. Expanding the U.S. market for solar applications will enhance our industries' competitive edge. The extension of the PURPA 80 MW limit is essential for the maturity of our industry and will insure a growing, more competitive and cost-effective solar industry.

The CHAIRMAN. Thank you very much, Mr. Sklar.
Mr. Boyd.

STATEMENT OF ROBERT T. BOYD, DIRECTOR OF REGULATORY AFFAIRS, U.S. WINDPOWER, INC.

Mr. BOYD. Thank you. I appreciate the opportunity to appear here today. Although I am in the middle of these two gentlemen, I am trying to sneak in the back door. Wind is not included in this bill.

We do support the bill as written, and we think it is a thoughtful bill that removes an artificial barrier against competition, and we thank Senator Domenici for submitting the bill. However, we would like him to think a little further and include wind in the bill.

I would like to talk in three general areas. One is the history of our company, the second is the history of the industry, and then third, tell you why this bill is important to us.

U.S. Windpower is the largest producer of wind turbines in the world, and the largest producer of power from the wind. We have been lucky to attract capital from some very large companies in the United States. The Hillman companies out of Pittsburgh, First Chicago Capital, All State Capital, and F.H. Prince Company, and that is an indication that there are some people that are financially astute that believe in this industry.

We had sales of approximately $80 million last year, and we employ 300 people. We have now, operational, 3700 turbines, which is 370 megawatts, and we produced over 600 million kilowatt hours in 1989. That is enough to supply the needs of about 100,000 homes in California.

Interestingly enough, we have talked some about tax credits. The tax credits for wind expired in 1985, at the end of 1985. Out of the 3,700 wind turbines we have installed, 2,600 of them have been installed since the end of 1985.

We also have been able to attract debt and equity from some large companies. We have several utility investors that have put money into our projects, and we are working now on the international market, and we have a project that we completed in Inner Mongolia last year. We have turbines going to Taiwan this year, and we will have a project in Spain that we are starting next year. So, there are a lot of opportunities overseas for us.

The wind industry started somewhat fitfully out of the tax credit era, and it has really developed, or the source of power has developed into a very clean and reliable one. There are now some 14,000 wind turbines in California, which represents about 1,400 megawatts. To put that in perspective, that is about one unit of a nuclear power plant.

Those turbines, last year, generated about 2.1 billion kilowatt hours, and that was 1 percent of California's energy needs. California is now, according to our governor, the fifth largest economy in the world, so it is not insignificant.

The capital cost, when we originally started back in 1981, was about $3,100 per installed kilowatt. Now, we are down around $1,000 installed kilowatt. The operation and maintenance costs have come down considerably, from around two-and-a-half cents to about a cent and a quarter. And the California Energy Commission in its last electricity report estimated that the life cycle cost of wind was around 5.3 cents per kilowatt hour.

We, in terms of technical progression, there is a consortium that has been formed recently between my company, Pacific Gas and Electric, and the Electric Power Research Institute to develop the next generation turbine, and we anticipate that this turbine will be producing power at the cost of fuel, plus operation and maintenance costs, and that would probably be somewhere in the neighborhood of 5 cents.

Availability of wind over the year has gone from the doldrums with our early machines, until we have 95 percent availability currently. One of the advantages in having that kind of availability with wind is that you really have a power plant with a whole bunch of generators. You have thousands of them out there. So, if you lose 5 percent of them, you haven't lost that much of your capacity, whereas, with a large central station plant, when one of your units goes down, you have lost significant capacity.

Why is this bill important to the wind industry? We, like the other technologies that you have been hearing about, benefit from economies of scale. We can benefit from purchasing if we build more units. We also spread our overhead costs over more units. And I was doing some back-of-the-envelope calculations this morning, and if we have $1,000 a kilowatt installed cost and are able to knock that cost down by $1,000 or save 10 percent on it, that means about a cent a kilowatt hour of savings. So, those kinds of things are very important.

We can also save money in some of the other areas, in terms of the maintenance costs, in terms of our financing, the transaction costs and also the permitting and development costs. These are not linear costs for the most part. We bear that cost anyway, whether it is an 80 megawatt size project or 200 megawatt size project.

Wind also has tremendous potential, both in this country and in other countries. The resource has been estimated by DOE over a 30-year period of time as being 870 million barrels of oil. We could take the conventional technology that we have now, and if we could spread that out all over the United States, we could have that kind of a capacity.

PG&E, the utility that our company deals with in Northern California, has estimated that there is 5,000 megawatts capacity in their service area, and that would be about 15 percent of their total generation right now.

Some of the states that are involved are primarily western states: Colorado, New Mexico, Idaho, Wyoming, Oregon, Oklahoma, Utah, Montana, West Virginia and North Dakota. All these states have tremendous wind potential. And if we can put large facilities in these areas, then we can open assembly plants and employ significant numbers of people in these states.

Also, the lesser-developed countries have a big stake in using these kinds of energy forms. A lot of them do not have indigenous fuel and have to import fuels. By using alternative technologies, the fuels in their country, they can use this capital to expand their economies and do things that they need to do.

Also, in Eastern European block countries, which are more developed, that have pollution problems, some of these alternative technologies can help in that regard.

The really, you know, obvious economic environmental and public policy benefits from wind, one of the things, and I think Mr. Bazor mentioned, is short lead times. We can develop wind plants over a period of time, and what this does, as compared to a large central station plant, is allow an expenditure of capital over a 10-year period in an incremental basis, rather than putting a large chunk of capital in up front and then ending up on the end with excess capacity. By using some of these technologies, you gradually bring these technologies on as the load develops, and it is an economic savings to the country.

Another thing is fuel diversity. It is not good for this country to depend on one or a couple of fuels. We need to get towards energy self-sufficiency, and that is both good for economic and national security.

And the last point is that it is environmentally clean and safe. We do not require any extraction from the ground, no refining, no transportation of fuels and no combustion. So, we avoid millions of tons of pollutants every year.

Again, I agree with Scott, that this bill is really a technical change. It does not cost anything to either the government or the people, and there will be ultimate savings in lower energy costs and technical innovation.

I would urge you to add wind to this bill.

[The prepared statement of Mr. Boyd follows:]

TESTIMONY OF
U.S. WINDPOWER, INC.
TO THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
CONCERNING
S.2415, THE SOLAR AND GEOTHERMAL POWER PRODUCTION INCENTIVES ACT OF 1990
MAY 15, 1990

INTRODUCTION

I am Robert T. Boyd, Director of Regulatory Affairs of U.S. Windpower, Inc. located in Livermore, California. Thank you for allowing me to appear before you to express the views of my company and the American Wind Energy Association on why lifting the 80MW size limitation for alternative energy technology power plants is beneficial to our country and why wind energy should also be included in S.2415.

U.S. Windpower supports S.2415 and congratulates Senator Domenici for authoring it. It is a thoughtful bill that eliminates an artificial barrier on the plant size of solar and geothermal power plants which had no rational basis. The 80MW size limitation made larger plants difficult without a lengthy and costly exemption process. We believe, however, that the bill does not go far enough and should include wind energy. Wind is considered as a solar technology and should be included for all the same reasons as the other two technologies included in the bill. Wind, as well as solar and geothermal energy, should be able to realize the same economies of scale which are afforded to cogeneration which has no plant size limit.

I will divide my testimony into three areas: (1) A short history of my company, (2) the history of the wind industry and (3) the importance of S.2415 to the further development of the wind industry.

U.S. WINDPOWER, INC.

U.S. Windpower, Inc., the largest wind energy company in the world, is a privately-held manufacturer, developer and operator of windpower plants. Among our stockholders are The Hillman Companies (Pittsburgh, Pa), First Chicago Capital Corporation (Chicago), Allstate Insurance Company (Cnicago) and F.H. Prince Companies (Chicago). The company had sales of over $80 million in 1989. We employ approximately 300 people. The company's windplants have a 370MW generation capacity and produced over 600 million KWH of electricity in 1989. That is enough electricity to provide the annual power needs of over 100,000 homes. Since 1981 U.S. Windpower has installed over 3700 turbines with invested capital of over $600 million. 2600 of these turbines (260MW) have been conventionally financed without federal tax credits since the expiration of the solar energy tax credit at the end of 1985. Major U.S. corporations which have provided equity or debt for U.S. Windpower are: John Hancock Insurance, Aetna, Chrysler Financial, Security Pacific Bank, Westinghouse and subsidiaries of Niagara Mohawk, Florida Power and Light, Iowa-Illinois Gas & Electric and PacificCorp. The company has domestic projects in California and Vermont, and foreign projects completed or in various stages of development in Inner Mongolia (1989), Taiwan (1990) and Spain (1991). We are negotiating in several other countries to develop additional projects.

THE WIND INDUSTRY

During the decade of the 1980's wind energy developed from the conceptual stage into the commercial stage until today it is a clean, reliable and cost effective source of electricity. Since the first few wind turbines were installed in 1981 in California, the number has expanded to 14,000 turbines representing approximately 1400MW of generating capacity. These turbines generated 2.125 billion kWh in 1989 or 1% of California's energy needs and enough power to provide the annual needs of a city the size of San Francisco. Over the last ten years the capital cost per installed KW for wind turbines has fallen from $3100/kW to $1000/kW. Operation and maintenance costs have fallen from 2.5 cents/kWh to 1.25 cents/kWh. These cost reductions have brought the cost per kWh for wind generated power to 7 to 9 cents/kWh. The California Energy Commission in its Energy Technology Status Report (1988) estimated that wind energy has a life cycle cost of as little as 5.3 cents/kWh. The U.S. Department of Energy has estimated the next generation wind turbine will produce power for 5-6 cents/kWh. U.S. Windpower has joined in a consortium with the Electric Power Research Institute and Pacific Gas and Electric Company to develop a wind turbine which will produce power at the cost of fuel plus operation and maintenance costs. The reliability of turbines manufactured over the past few years has improved markedly. The availability is currently 95% as opposed to 60% in 1981. This means that 95% of the turbines are available to operate at any given time as opposed to large central station plants where a failure can take hundreds of MW out of service for some period of time.

THE IMPORTANCE OF INCREASED PLANT SIZE TO THE WIND INDUSTRY

As a matter of public policy there is no reason why a wind energy power plant should be limited to 30MW in order to be a qualifying facility and be exempt from Federal Energy Regulatory Commission jurisdiction. This size limitation, which is not imposed upon congeneration facilities, works a hardship on wind energy plants by not allowing them to take advantage of the economies of scale inherent in larger facilities.

In building windplants there are substantial savings to be realized throughout the whole project chain. Significant savings can be obtained in purchasing for both manufacturing and project materials, development and construction costs, transaction costs and operation and maintenance costs.
A doubling or tripling of a manufacturing plan will allow 10 - 20% savings in component purchases and the spreading of overhead over a larger number of units. Permitting and development costs do not increase in a linear manner with

increased project size. Permitting and development costs would be approximately the same for an 80MW project as a 200 MW project. Similarly the transaction costs (financing and legal costs) would also stay close to the same for an 80MW or 200 MW project. Economies of scale are also realized in the equipment needed, parts purchasing and maintenance staffing of projects after completion for facilities operation and maintenance.

Wind energy has a tremendous potential for future development in the United States and the rest of the world. There is more potential energy above the ground in the wind and the sun than there is below it. There are 37 states that have significant wind potential in the United States. The Department of Energy estimates that the power over the continental United States that is accessible utilizing current technology is equivalent to 870 billion barrels of oil over 30 years - and that occurs every 30 years. Several of these states are not densely populated and have large land areas used for grazing and dry farming which are compatible with wind energy development. Some of these high wind potential states include Colorado, New Mexico, Idaho, Wyoming, Oregon, Oklahoma, Utah, Montana, West Virginia and North Dakota. Location of windplants and perhaps assembly facilities in some of these states create potential employment opportunities. Many countries in the world can benefit by using wind energy. The lesser developed countries with little or no indigenous fuels can benefit because in using wind they can avoid importing costly fuels and use the resultant savings to help develop their economies. Some of the more developed countries can use wind energy to offset the pollution caused by the older technology used in their electrical generation plants.

Utilizing wind energy offers some obvious economic, environmental and public policy benefits. Windplants require very short lead times from design through construction. Conventional large baseload utility plants require 7-10 years from conception to operation while windplants can be added in small increments from year to year keeping pace with annually increasing electrical demand. These incremental additions facilitate utility planning to spread out capital expenditures and not bring on large blocks of capacity all at once creating large quantities of excess capacity.

Using wind energy helps the county to establish fuel diversity so that we are not too heavily dependant on fuel sources which are subject to scarcity and price uncertainty. Since wind is a "free" fuel it helps to add to the country's energy self-sufficiency which has both economic and national security implications. Utilizing wind energy also helps spread the technical risk associated with development of other new technologies and some existing generation technologies.

Wind energy is environmentally clean and safe. Wind is a fuel which requires no extraction of resources from the earth, no refining or processing, no transportation of fuels, no combustion and no waste products. The increased use of wind energy will avoid millions of tons of polluting gasses which are released into the air each year. Every kWh generated by wind energy is an important contribution to cleaner air.

CONCLUSION

S.2415 is a bill making technical changes which put alternative energy at parity with cogeneration. There is no cost to the government or the American people. In fact, there will be an ultimate savings to all parties as the resultant economic benefits are passed on in the form of lower energy costs and technological innovation.

Wind energy should be a part of this bill. Wind energy is clean, proven, cost effective and has tremendous potential for providing significant amounts of power in the United States and around the world. We urge you to pass this legislation and in keeping with good long-term energy policy to include wind energy.

American Wind Energy Association

March 30, 1990
FOR IMMEDIATE RELEASE
FOR FURTHER INFORMATION CALL: Randy Swisher or Earl Kelly at 703-276-8334;
or Paul Gipe at 805-822-7956

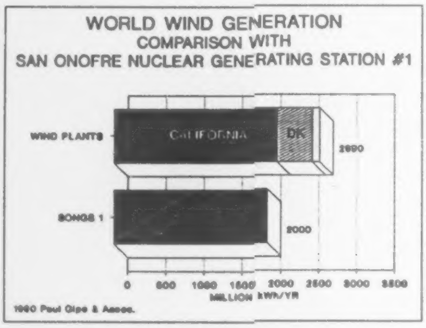
WIND ENERGY IN THE 80s -- A DECADE OF DEVELOPMENT

Wind energy came of age during the 1980s, emerging from the domain of government research and backyard inventors. After a sputtering start following the oil embargoes of the 70s, the industry grew dramatically in the 80s. Not since it was harnessed to power the world's sailing ships and pump water from the lowlands of Northern Europe has wind energy been employed on such a grand scale as it is today in California and Denmark.

The wind industry's tremendous growth during the 1980s has pushed the technology beyond the theoretical stage and into commercial reality. Wind's success in California, Hawaii, and Denmark demonstrates that the technology works, and that it can produce sizable amounts of electricity which can be readily integrated into conventional utility systems. Wind energy's rapid progress during the 1980's has also shown that the technology is now economically competitive. In short, wind energy has matured and is now ready to take its place among conventional energy resources as a clean, reliable source of electrcity.

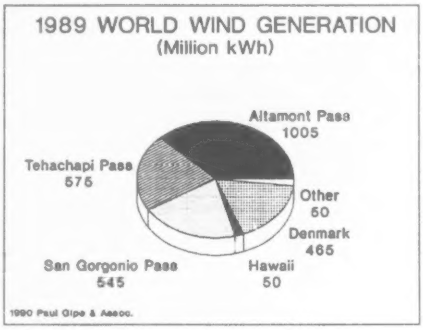
Progress Worldwide

Wind energy is the most successful solar-electric technology to result from the scramble to develop alternative forms of energy during the 70s. Today wind turbines worldwide generate as much electricity as that produced by a medium-size nuclear reactor or a coal-fired power plant.


WORLD WIND GENERATION
COMPARISON WITH
SAN ONOFRE NUCLEAR GENERATING STATION #1

1990 Paul Gipe & Assoc.

Wind turbines now provide commercial bulk power in California, Hawaii, Denmark, the Netherlands, and India. California accounts for 80% of the world's wind generation; Denmark produces much of the remainder.


1989 WORLD WIND GENERATION
(Million kWh)

1990 Paul Gipe & Assoc.

Progress in California

Unquestionably wind energy has made its most significant contribution in California. With 11% of the country's population and the world's sixth largest economy California is both a major producer and consumer of energy.

Because of the progressive policies adopted during the late 1970s and early 1980s, California has become a world model for renewable energy development. More than 10% of the state's electricity is produced by such alternative sources as

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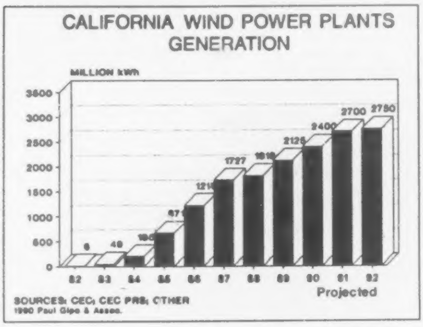
wind, solar thermal, photovoltaics, geothermal, and biomass. In excess of $2.5 billion has been invested in wind energy alone.

In 1989, for the first time, California's wind generation exceeded two billion kilowatt-hours. Today California's wind turbines generate enough electricity to meet the residential needs of over 900,000 people--more than the population of San Francisco or Washington, D.C.

By the mid 1990s sales of wind generated electricity to the state's largest electric utilities Southern California Edison Co. (SCE) and Pacific Gas & Electric Co. (PG&E) are expected to near three billion kWh, enough electricity for more than one million people.



During 1989 these wind power plants, as the arrays of multiple wind turbines are known, produced

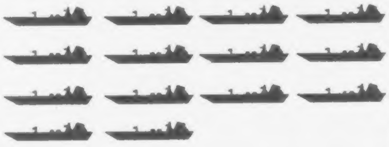
- 1.2% of PG&E's estimated consumption,
- 1.5% of SCE's estimated consumption,
- as much electricity as that produced by California's oil-fired power plants,
- as much electricity as that saved by all residential building and appliance standards from 1977 to 1985,
- nearly as much as that imported to California from British Columbia Hydro in a typical year,
- about one-third of imports to California from Southwest coal and nuclear plants.

California's wind plants effectively save the energy equivalent of 3.5 million barrels of oil per year that would have otherwise been needed to generate the same amount of electricity in a conventional power plant.

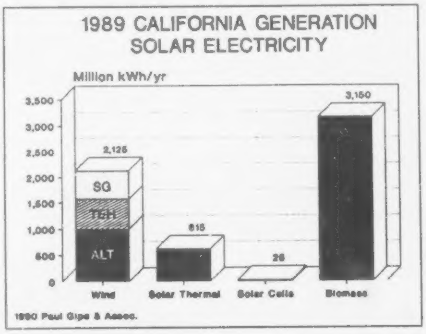
If used for transportation 1989's wind generation would have nearly equaled the South Coast Air Quality Management District's estimate of the amount of electricity needed to power the first phase of electric vehicle use in the Los Angeles Basin.

CALIFORNIA WIND GENERATION
PRODUCES THE ENERGY EQUIVALENT OF
3.5 MILLION BARRELS OF OIL

OR 14 TIMES THE EXXON VALDEZ OIL SPILL



Wind generation has been characterized by the Chairman of the California Energy Commission, Charles Imbrecht, as a "remarkable success story" in the state. George Maneatis, President of Pacific Gas & Electric Co., has called wind one of the most successful forms of alternative energy developed in California. And a PG&E study has found that "wind energy will become the most economic new base load source by the year 2002."



California's wind plants are privately owned and operated, and range in size from only a few wind turbines to as many as several thousand. They are concentrated in three mountain passes: Altamont, east of San Francisco; Tehachapi, northeast of Los Angeles; and San Gorgonio, east of Los Angeles. Wind power plants have also been built in Solano County near the confluence of the San Joaquin and Sacramento Rivers, and in the Pacheco Pass southeast of San Francisco.

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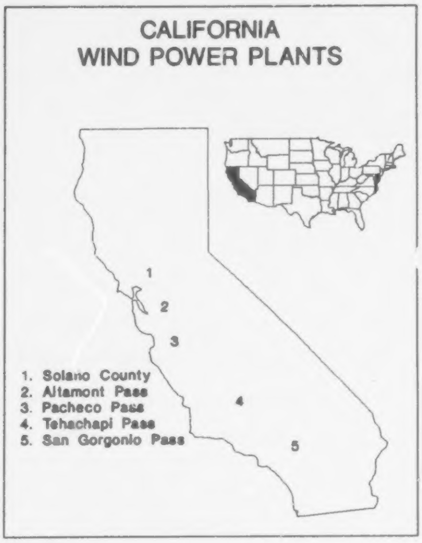
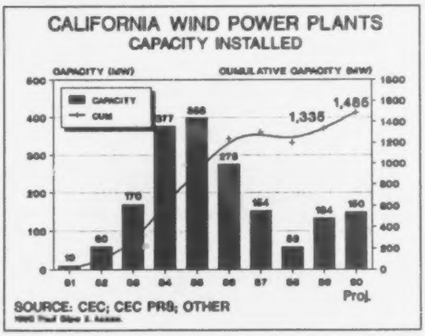
CALIFORNIA
WIND POWER PLANTS



Progress in the Technology

Wind energy continues to expand not only in California and Denmark, but in other countries as well because improvements in the technology have led to greater reliability and productivity at lower costs than was possible only a few years ago. The turbines installed during the past decade provide a large base upon which the technology has been able to build. There are now more than 14,000 wind turbines, representing nearly 1,350 Megawatts (MW) of generating capacity, operating in California. Another 2,400 turbines operate in Denmark.

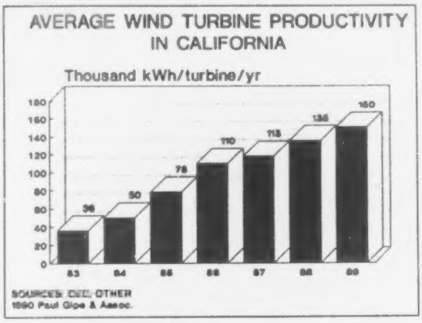
CALIFORNIA WIND POWER PLANTS
CAPACITY INSTALLED



SOURCE: CEC; CEC PRS; OTHER
1990 Paul Gipe & Assoc.

With the experience gained from these turbines the industry has steadily increased performance not only by refining the design of new wind turbines but also by improving the operation of existing ones. Today, turbines in better performing projects are available for operation about 95% of the time.

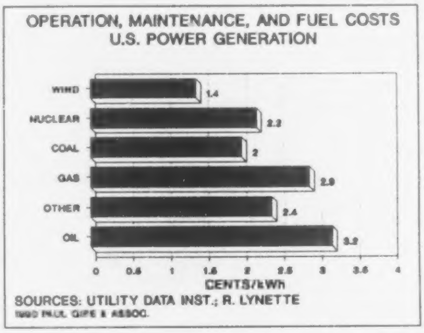
AVERAGE WIND TURBINE PRODUCTIVITY
IN CALIFORNIA



SOURCES: CEC; OTHER
1990 Paul Gipe & Assoc.

Wind plants, like other forms of solar energy, are capital intensive. But they are less costly to operate, maintain, and fuel than conventional power plants. Wind plants cost about 1.4 cents/kWh (about half that of coal and nuclear) to operate and maintain.

OPERATION, MAINTENANCE, AND FUEL COSTS
U.S. POWER GENERATION



SOURCES: UTILITY DATA INST.; R. LYNETTE
1990 PAUL GIPE & ASSOC.

The cost of California's wind energy compares favorably to the cost of more conventional sources of electricity, such as nuclear power. According to a recent report by the Department of Energy, the cost of wind-generated electricity at excellent sites (16 mph) should cost from 5 to 7 cents/kWh, and at sites typical of the Great Plains (14-16 mph), from 6 to 9 cents/kWh.

The staff of the Northwest Power Planning Council estimates that there are enough windy sites in the Pacific Northwest to produce nearly ten times the electricity generated by California's

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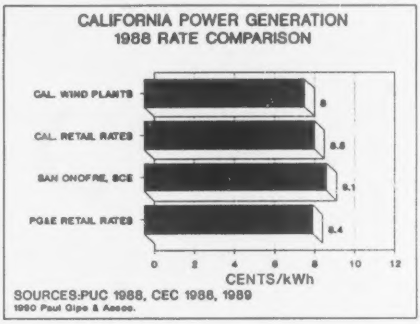
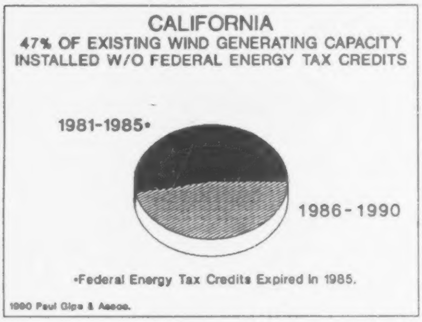
wind plants at a cost competitive with conventional power plants burning coal.


CALIFORNIA POWER GENERATION
1988 RATE COMPARISON

SOURCES:PUC 1988, CEC 1988, 1989
1990 Paul Gipe & Assoc.

Because of improved cost effectiveness wind turbines continue to be installed despite the loss of tax credits that spawned the industry's development. Nearly half of today's wind generating capacity in California has been installed without federal energy tax credits.


CALIFORNIA
47% OF EXISTING WIND GENERATING CAPACITY INSTALLED W/O FEDERAL ENERGY TAX CREDITS

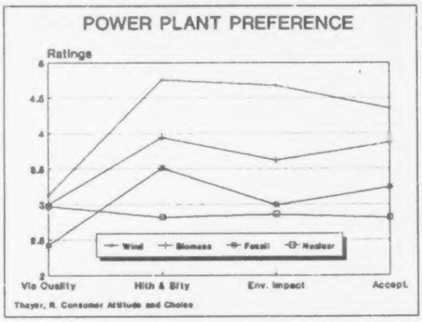
•Federal Energy Tax Credits Expired In 1985.
1990 Paul Gipe & Assoc.

Progress in Improving Air Quality

Wind energy is not only renewable, it's also a source of clean, non-polluting electricity. Unlike conventional power plants, wind plants emit no air pollutants, or greenhouse gases. In 1989 California's wind power plants offset the emission of more than 2 billion pounds of carbon dioxide, and 13 million pounds of other pollutants that would have otherwise been produced. It would take a forest of from 90 to 175 million trees to provide the same air quality benefit.

Progress in the Future

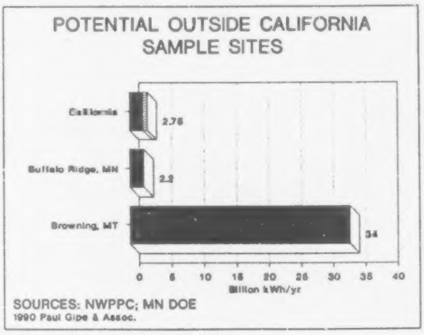
Though wind energy isn't without critics, numerous public opinion surveys have consistently shown that the public prefers wind energy over conventional sources of generation, and over some forms of alternative energy as well. This preference is most marked with respect to health and safety, and environmental impact. It's this preference for a clean, renewable resource that will assure continuing expansion of wind energy.


POWER PLANT PREFERENCE

Thayer, R. Consumer Attitude and Choice

Though currently wind energy produces only 0.1% of the nation's electricity, it could produce a significantly greater amount during the next decade. Recently the Department of Energy estimated that by the year 2000 wind--with business as usual--could supply 10 times more electricity than produced in California today.

Realistically wind could meet 5-10% of the nation's electricity supply. The Great Plains contains a tremendous wind resource. One ridge in Southwestern Minnesota could produce as much wind-generated electricity as that produced in California today. And just one site in Montana could provide 17 times California's current wind generation.


POTENTIAL OUTSIDE CALIFORNIA
SAMPLE SITES

SOURCES: NWPPC; MN DOE
1990 Paul Gipe & Assoc.

The CHAIRMAN. Thank you very much, Mr. Boyd.

Mr. Sklar, on the Clean Air Act, there was an amendment proposed. I understand it was sponsored by the solar energy industries, and whenever they had hearings on that, can you tell us what that amendment did?

Mr. SKLAR. That bill was not on our request. That was put in by Senator McCain, and it was to provide some regulatory incentives. The way the bill was written was not what we had expected, and I am not quite sure what it does at the moment, sir.

The CHAIRMAN. Well, I ask that question in all seriousness because we could not tell exactly what it did or why it was proposed, and that is why I ask you the question now.

Mr. SKLAR. It is a good question.

The CHAIRMAN. Can you tell me about—I am interested in photovoltaic, I am interested in all of these renewable technologies. How can the Germans go to 10 megawatts in that geographic clime?

Mr. SKLAR. Well, I will tell you what is happening, and I always bring my pictures to these committees because I enjoy to do that, and this is an Alabama power company demonstration of the new amorphous technology. I am trying to get a big one in Louisiana sometime, but right now we have gotten down to Alabama, and Alabama and Texas were on each side of the states. But the fact of the matter is that there are a smaller group of photovoltaic companies in Germany than there are in the United States in terms of manufacturers.

The competitive situation is, we have some large players in photovoltaic manufacturing; most of them are small businesses. As a matter of fact, this entire industry is mostly small business. In Germany, they are all the largest multinational corporations. Their photovoltaic budget is twice our own in terms of R&D, and what they are trying to do is essentially through massive subsidy, get the amorphous technology, the thin film technology, with the utilities co- investing, to demonstrate large scale applications. They believe that by creating the demand, they will be able to incentivize these manufacturers to scale up and do a second generation kind of technology. Our industry is slightly ahead in the robotic side. SolarX, which is an Amoco subsidiary, is the first U.S. company that has gone totally robotics. I would love to bring you to their facility in Frederick to take a look at it, but they are doing it, in short, because what they believe is the technology is important, they are having severe environmental problems there, and it is a way to just build the demand on the technology, and that is why they are doing it.

The CHAIRMAN. Really, my question has to do with Germany and its latitude.

Mr. SKLAR. Oh, I see. Sure.

The CHAIRMAN. I mean, is there a future for photovoltaics, assuming you can get the cost down, in that northern latitude?

Mr. SKLAR. Absolutely. There is no question. The real issue is it is the amount of high spectrum sunlight. It is not the temperature. I mean, I have small applications of photovoltaics in my house in Virginia, and you just have to size it about 15 percent more in terms of the panels to get the same amount of energy in the more northern latitudes to compensate with the sunlight. That is really the issue. It is the square footage in terms of doing it. But yes, it will work, ultimately, I expect, economically in terms of utility application. It does so now in remote applications.

The CHAIRMAN. All through the winter though, they have very short winters, and the sun is very low. What do you do?

Mr. SKLAR. Oh, thank God we have batteries for the remote applications. But I expect in all these technologies is that what we will be using, whether it is natural gas here, or batteries or whatever, the utilities—our technology, obviously is constrained by the amount of sunlight. We cannot argue that. But what we do believe is that there is an intelligent way to integrate this technology into the utility sector to meet certain demand requirements, and it is not just peak demand.

So, we are in the process of understanding that. We spent a lot of time in the solar trade association, utility council, composed of fairly large utility companies, and we are doing a lot of seminars on procurement officers on when this makes sense and when it does not.

The CHAIRMAN. Let me make clear, I want to encourage photovoltaic, I want to encourage all solar energy, but I just wonder whether there is a future for photovoltaic in those northern latitudes as a central power source?

Mr. SKLAR. I think in Germany, central to southern Germany, yes. I do not believe in the Scandinavian countries, probably not, but in Germany, yes. I think they have made that commitment.

The CHAIRMAN. All right. Mr. Boyd, I understand there has been development problems with the turbines. Somehow, these windmills break down. If that is so, my question is, why is that? It seems to me that a windmill ought to work, it ought to be very easy to keep, I mean, you should not have any R&D problems. You ought to just be able to build one and keep it oiled, and that is all there is to it. What is the problem?

Mr. BOYD. Well, I do not know. I was raised on a ranch and farm, and I learned early on that anything mechanical breaks. When you have an environment like the wind is, which changes instantaneously in direction and intensity, that is a lot of stress on a machine, and one of the things that we did not know was how severe that stress was.

The early wind turbines had a lot of problems. The turbines today are very reliable. Our average turbine will run between three and four thousand hours a year. Put that in terms of something that we all understand is, that that is like driving your car at 50 miles an hour for 150,000, 200,000 miles in a year. So it is a fairly severe duty cycle.

The CHAIRMAN. By the way, in Altamont Pass, which I fly over every other year or so, during the day time those windmills are not turning. Is that because it is a night phenomenon, the wind there?

Mr. BOYD. No. Really, the wind phenomenon there is a summer wind. It starts, blows, I think 70 percent of our energy comes between May and September, and it starts in early afternoon and blows through the night. If you were there late afternoon in the summertime, you can almost guarantee that you will be seeing the windmills turning. If you are there in December or January, we produce about 1 percent of our energy during each of those months, and the probability of seeing them operating then is pretty small.

The **Chairman**. We usually fly over there in the mornings, seems like.

Mr. **Boyd**. The morning is a still time generally. The phenomenon we have in that area is that the land heats up and then pulls the moist air in from the coast, the cool air.

The **Chairman**. But most of them are working?

Mr. **Boyd**. Yes. PG&E, in a recent talk they gave, said that about 80 percent of the turbines are operating there. The early problems that we have, I think have been overcome. A lot of the older projects that did not operate successfully have either been taken down or they have been retrofitted so that they are operating now.

The production of over two billion kilowatt hours last year should speak for itself and this is from the utilities records.

The **Chairman**. Mr. Bazor, the technology you are using now is the parabolic reflectors with the little, what do you call them, pipes in the middle?

Mr. **Bazor**. Yes, sir. They are parabolic reflectors.

The **Chairman**. What is the name of that——

Mr. **Bazor**. Solar thermal technology, Mr. Chairman.

The **Chairman**. Right, solar thermal, but using the parabolic reflectors——

Mr. **Bazor**. That is exactly right, Mr. Chairman, and using this tube here, these things are about 12 feet long, and this kind of acts as a thermos, has a thermos bottle effect. This is what we basically invented to make this solar thermal technology commercial. That is the key to it.

The **Chairman**. You have your 80 megawatt plant operating, which I have seen. Is that the same technology that you would use on a larger plant?

Mr. **Bazor**. Sir, you say you have seen it. Have you been to our unit?

The **Chairman**. I have seen the one out in California.

Mr. **Bazor**. Yes, sir. I wanted to give you a special invitation to come by and look at it if you have not been there.

The **Chairman**. I do not know whether that is the 80 megawatt, or whether that was the predecessor of that.

Mr. **Bazor**. If you ever just come down there and just walk through it, you will be impressed with it, but anyhow, yes, sir——

The **Chairman**. I mean, I have seen the parabolic reflectors.

Mr. **Bazor**. This is basically the same technology, but we have got on the drawing board right now, several improvements to this technology that would allow us to get this cost down, coupled with the upscaling. We are about 60 percent mature as far as developing this technology, Mr. Chairman.

The **Chairman**. What else is to develop? I know you have got the seals that were the problem there for a while.

Mr. **Bazor**. Yeah. We pretty well have that hammered out. We had a guy that did not have any engineering background to solve that for us pretty well. But anyhow, we have on the drawing board now, things like front surfacing the mirrors. Right now, we have a back surface of mirrors and we have to have a high quality of glass to where we get accurate reflectivity. When the sun comes through, bounces back to this part of the facility.

Now, if we can figure out something to front surface that mirror, we can use anything for the backup then, and it would reduce costs considerably. We have got a multitude of things. We are looking at direct steam generation. Instead of using a heat collecting fluid, which runs out through the fields and collects the heat and runs to a power block that turns water into steam, we drive a conventional turbine generator, we are looking at the possibility of using water. And if you are familiar with boilers, if you know what the kind of boiler is that does not have a steam drum, putting water in one side, and when it runs through these collectors, comes out the other side steam. Now, we have a heck of a long way to go on that, but we think we can get there.

We are looking at the support structures. Anything that we can do to lower the cost of the support structures that would bring the cost down, anything that we could do to lower the cost in construction. We have gone to a lot of assembly line-type of construction to where you assemble these collector elements in one central area and then haul them out and set them. We had to redesign trusses and supports to do that.

So we are always, and we have got a continuing program going on to reduce this cost, but we are getting to the point now where we are realizing that the pure research and development is not going to get us all the way. That is the reason we need this upsizing.

As far as the size limit, we are never going to be 1,000 megawatts, 600 megawatts. We are not going to compete in that size range, because if you look at our solar fields, the bigger they are, the further you have got to bring that oil in and keep it hot until you get to the power blocks. So, there is a limitation. The way it looks right now, if we get to 250 megawatts, that would be on the top side, 150 on the low side, but I do not want to sit up here and suggest that we ought to put some kind of other artificial limit on it. I would still like for the marketplace and the technology to dictate that limit.

The CHAIRMAN. Well, you are not asking for the marketplace to do it, because PURPA is a compulsion outside of the marketplace.

Mr. BAZOR. Well sir, I do not know of anybody under PURPA that is required to give you a certain price for your power, and I heard this awhile ago about the capacity. If a utility does not need capacity, you do not get capacity payments, I am just a construction man talking now, but unless there is something I do not know about the Act, as far as if the utility does not need capacity, you do not get paid that part of the capacity payments. Maybe I am wrong, but I do not think so.

The CHAIRMAN. Well, in the past, some of the PUCs have used the power of PURPA to jawbone electric utility industries to ask for and to pay for some projects.

Mr. BAZOR. Yes, sir, and if we are saying that the PUCs are doing that, I cannot control that. But they will have to answer to the state and the rate payers if they are cajoling utilities into paying more than they should be. Now, I think some of those decisions were made when the oil prices were projected to go out of sight, and they thought at that time, that it was going to be a darn good investment for the rate payers. Just because it turned out not to do, they shot craps and lost, just like a lot of people in the nuclear industry did.

The **Chairman**. Let me ask you, why is it that you need to use natural gas?

Mr. **Bazor**. Well, it is the second cleanest fuel, except the one we use, which is the sun. That is number one. Number two, we do not have a way right now to store energy during the day, although we are working on that, trying to create a battery system where we can generate electricity during the day, and then produce it at night when we are still on peak and the utilities need it the worse, which in the summer peak, if I am remembering right, the summertime peak runs about 10:30 to 11:00 at night.

The **Chairman**. When is the peak, by the way?

Mr. **Bazor**. If I am remembering right, Senator, I was trying to remember awhile ago. You have to bear in mind, at my age you are kind of forgetful. I think it is from about, summer peaks, about from 9:00 in the morning until 11:00 at night. When the sun goes down that is when we fire up the heaters to supplement that power, so that we can furnish the power during the time that the utility needs it the most.

The **Chairman**. I mean the peak lasts from—it does not sound like much of a peak. I mean, that is more than half of the day.

Mr. **Bazor**. In the summertime it is pretty hot down there. You know all Los Angeles is is just another part of the desert.

The **Chairman**. Well, I know that.

Mr. **Bazor**. It gets pretty hot down there, and it stays hot a pretty good while. I would have to clarify that. It may be a little shorter than that, but I do not think I am far off.

The **Chairman**. When do you fire up your gas turbines?

Mr. **Bazor**. When the sun starts going down, about 5:00 in the afternoon. Now, we are not incentivized to burn gas. It is the cheapest fuel we use, so we do not use it until we actually have to. Out of that billion kilowatt hours I was talking about awhile ago, 750, at least 750 million of those were produced on solar alone.

The **Chairman**. Well, it is 25 percent. You used the full 25 percent of natural gas.

Mr. **Bazor**. Normally, we do.

The **Chairman**. And roughly about 5 p.m. until 11 p.m.——

Mr. **Bazor**. No, I said 9 a.m., and I have got to clarify that. Like I say, I do not remember exactly when it is, but if I remember right, from about 9 or 10 in summer.

The **Chairman**. No, I mean when you use natural gas.

Mr. **Bazor**. Oh, when we use natural gas in the evening. Something like that, yes, sir.

The **Chairman**. About 5 to 11.

Why is QF status necessary? If you are able to compete or you are close to that, what does QF get you?

Mr. **Bazor**. Well, PURPA has gone through a shake-out period, Mr. Chairman. And finally, the investors are relatively satisfied with it now, with a risk that they are willing to assume. Now, bear in mind, we have technologies about 60 percent up to maturity scale, and if we did not have to have investors, well, I do not know whether we would need any of this or not. But unfortunately, we have got to sell this thing, and what they get—they get nervous anytime you talk about changing anything.

Now, if PURPA went away, for instance, I think they would be nervous, and I just do not know what the future would hold, as far as what they are concerned about, because they are already nervous, with the savings and loan thing going on, everything is getting tight as it can be as far as investments go anyhow.

The CHAIRMAN. Well, I know, but you say they want a consistent policy. Why pass this? I mean, that is a change in policy. What does it get you?

Mr. BAZOR. Well, even I think, upscaling is a no-brainer for them, sir. If you upscale there is no risk in that. They are looking for things like, will this contract go away.

And another thing, too, it is not only investors, but the people that furnish the long term debt for 20 years out that are looking for this consistency. And I do not mean to be flippant when I say that they can understand the upscaling, because we have done it twice. We went from 14 megawatts to 30, and then from 30 to 80. You know, they are accustomed to seeing the benefit of that.

The CHAIRMAN. Well, I mean, there is nothing that would prevent you right now from building a 250 megawatt unit and making a deal with the utility to furnish the electricity, is there?

Mr. BAZOR. Just that our cost is too high right now. We have got to get it down. We are looking forward to the day we can do that. We would like nothing better than to sell a 250-megawatt plant to a utility, but we have got to get the cost down to where we are competitive.

The CHAIRMAN. Well, suppose we gave you, actually you would have to have exemption from the Holding Company Act, which QF status would give you. Suppose we just gave you the exemption from the Holding Company Act, and did not have these other elements in it, would that be enough?

Mr. BAZOR. Are you talking about exemptions from the Holding Company Act and PURPA goes away, or what? I do not understand the question.

The CHAIRMAN. Yes. In other words, we exempt you from the Holding Company Act for renewable fuels, above 80 megawatts, but you do not get the other exemptions here. I mean, you do not have the requirement of purchase, the interconnect.

Mr. BAZOR. Well, I think eventually that dollars and cents is going to make the difference. Now, that is the way the market is heading. That is the way PURPA is shaking out. But here again, as far as the investors go, I think if you change it, there will be a shake-out period. If you change anything there will be a shake-out period. They are going to be nervous. And by the way, in the meantime, we are not going to be in business.

The CHAIRMAN. That is what I am trying to understand. What is it that this law gives you, aside from exemption under the Holding Company Act, that you need?

Mr. BAZOR. It gives us the opportunity to go from 80 megawatts to whatever size our optimum cost is, and I am saying that I am guessing that that should be between 150 and 250 megawatts, probably closer to 150 to 180 megawatts, and that allows us to get our costs down to be competitive.

The **Chairman**. Well, what is it that gives you that opportunity? Why would you not have that opportunity by being exempted from the Holding Company Act?

Mr. **Bazor**. Because we cannot sell our power right now at a competitive price. At eight cents, eight cents is not competitive, and that is where we are now. That is the reason we have got to get our costs down.

The **Chairman**. You cannot sell it now because of the market?

Mr. **Bazor**. That is right. We are not going in the future. Now, we have still got under contract, three contracts or four contracts for four units that we will be able to bring to fruition, and after that, we are galloping towards the cliff, and if we do not get our costs down in that period of time to where we are competitive in the marketplace, and I am saying it is going to be closer to five cents than it is six cents, well, we have no place else to go. We are dead.

The **Chairman**. With this PURPA exemption, would you be able to sell your power if your cost is above this five cents or whatever the competitive level is?

Mr. **Bazor**. I do not think we would. I think our only salvation is to get down to that cost level. I think it is going to be a matter of cents per kilowatt hour in the future markets. That is what we are running into for every place we are looking.

The **Chairman**. All right. If you can get your costs down to five cents, do you need PURPA to be able to sell your power?

Mr. **Bazor**. Yes, we need PURPA, because we still cannot be—we are still going to have to have investors to buy, and they are going to have to have some protection over the lifetime of the contracts and what have you, that they are going to get a return, or they are going to get their loans paid back, and they are going to get a return on their investments, because basically, we sell a financial instrument. We are out there competing in the private financial market, just like people are leasing airplanes and everything else. We have to give them a greater return that is competitive in the marketplace.

We also need to let them know that all their concerns are being answered in their due diligence. So, they are going to have to have some protection that they are going to get a return on their investment and their money is going to be paid back.

The **Chairman**. Well, I still do not understand. Perhaps this will become clear with the questioning by Senator Domenici.

Senator **Domenici**. Let me ask Scott this question. There is not any doubt that in the past, in the early days of PURPA that there were a lot of horror stories about forcing inordinate-priced energy of this type on utilities?

Mr. **Sklar**. Right.

Senator **Domenici**. Now, what we understand is that has been changing dramatically, and that we are getting very close to having to have market-priced energy. Is that not correct?

Mr. **Sklar**. That is absolutely correct. It takes a shake-out period, and we went through it, and it is just a normal process of maturing in a new kind of market.

Senator **Domenici**. All right. Now, if you did not have PURPA, as I understand it, you would not have the opportunity to force the negotiations with the utility company that PURPA imposes?

Mr. **Sklar**. That is right.

Senator **Domenici**. And thus, they would ignore this kind of energy and move toward others that have qualities that are different from this, and they would say goodbye. Is that how you see it?

Mr. **Sklar**. Yes. Mostly not—utilities are like any other human being, composed of human beings. They generally like to work with what they know. And so, with newer and emerging technologies, it is important to have that incentive at this time in our development.

Senator **Domenici**. So, if there was not a need to be competitive, and if you were not convinced that competitiveness is a function of scale, if there was no need to be competitive because PURPA was a perpetual advantage, then you would not be here asking for a change, would you?

Mr. **Sklar**. That is absolutely right, Senator. The U.S. solar industry believes that we are making good on our commitment to bring down the costs, and this is only one more tool to allow us to do that, a minor tool at that.

Senator **Domenici**. Is not the avoided cost changing dramatically in terms of what the PUCs are saying should be paid for this kind of energy?

Mr. **Sklar**. Indeed, that is so, Senator. Across the country from the late 1970s to now, those rates have gone down, and we have had to be competitive to be able to deal with that.

Senator **Domenici**. So to the extent that solar energy, geothermal, and wind are moving in the direction of becoming more competitive, it is your position in behalf of the industry, and Mr. Bazor's contention, that we need to take the cap off so that we will retain the advantages of negotiation and mandatory hook-up, but you are convinced that the utility commissions are moving in the direction of finalizing that kind of transaction, more and more in the direction of market cost energy. Is that correct?

Mr. **Sklar**. My view and understanding is that all the utilities and all the state utility commissions are demanding we be more competitive. That is the way PURPA is shaking out, and this size extension will do, just essentially one simple, truly understood concept, allow the technology and economy of scale to be more cost effective, which was the original purpose that we passed this legislation originally. We are making good on that.

Senator **Domenici**. All right. The Chairman is asking about getting rid of PURPA and doing something with the Public Utility Holding Company Act, but the point you are making is, that utilities are going to deal with what they are used to dealing with, and this kind of energy will be left out unless they are forced to at least negotiate with them, even if they are insisting on efficiencies of scale and moving toward the market. This is an advantage that produces consistency in the industry and reliability in terms of moving ahead.

Mr. **Sklar**. That is absolutely, I could not have said it better myself, Senator. That is perfect.

Mr. BAZOR. Senator, if I may, I would like to add one thing to that. I think all that is true, but I think it is going to be dollars and cents. I think if you are not competitive in the future, you are not going to be around. And that is the reason we need this.

Senator DOMENICI. Yes. And you need it so that you can continue to move with technology toward more competitiveness. And without it, you will not move in that direction.

Mr. BAZOR. We have to; we have got to move in that direction. And without it, it may be a effort in futility.

Senator MCCLURE. Let me try to summarize as I see it, because I really do want to understand. Mr. Bazor, you have indicated that you cannot just go out and build and sell today. You need PURPA in order to be able to do that, which implies that there is some advantage in PURPA to you.

It seems to me, as I go through all the things that PURPA does and does not do, there is one thing that PURPA does that is essential, that it gives you access to a market.

Mr. SKLAR. Right.

Mr. BAZOR. Yes, sir. That is correct.

Senator MCCLURE. And without that guaranteed access to the market, you are likely not going to make it.

Mr. BAZOR. That is correct. And another point, just to clarify it, I may have confused you, Mr. Chairman, in my articulation of this, is that under the current power purchase agreements, they are marginal, but the ones that we have under contract now, we can build. And that was the reason I was saying that, if we did not get competitive at the end of those contracts, we are dead. We are going to have to be down to 5 or 6 cents.

Senator MCCLURE. Well, if you go through the list of things that PURPA does, and I do not mean this to be an exhaustive listing——

The CHAIRMAN. Would you yield at this point? When you say access to the market, now if you are competitive and we repeal the Holding Company Act exemption, then do you not have access?

Senator MCCLURE. You do not have guaranteed access. You have to——

The CHAIRMAN. You do not have the compulsion of purchase?

Senator MCCLURE. That is correct.

The CHAIRMAN. Well, that is something different from access, it seems to me.

Senator MCCLURE. Well, however you want to say it. I will buy that correction. PURPA mandates that the utility purchase, if you meet all the tests. That kind of access you do not have without the PURPA compulsion. It has a PUHCA exemption, it has the Federal Power Act exemption, it has the utility commission jurisdiction exemption, and it has full avoided cost calculations. But in addition to those, it has mandatory interconnect and mandatory purchase. And it is those last two items that give you the market that you might not have, just on the basis of negotiations or price alone.

Mr. BAZOR. Yes, sir. And another thing, those first three items you named, Senator, keeps your investors comfortable.

Senator MCCLURE. Mr. Boyd, you had something to say.

Mr. BOYD. Yes, I would like to make a point. I think that what the Chairman is saying is true, that PURPA is leading us in a direction. We are just not there yet. My state, California for example, has a bidding process that they are instituting, and what this will do is allow us to have competitive bids. And I think that will happen all over the country. But until we have access to those markets all over the country that we still need the PURPA legislation. I am all for what you propose in the long run, but we are not there yet.

Senator McClure. Let me ask you just a couple of other questions that deal with the cost of operation and reliability. Mr. Boyd, the Chairman asked you some question about why do your turbines keep breaking down. You say, well, we learned how to build them better and your reliability is now going up. What is your on-line availability?

Mr. Boyd. 95 percent.

Senator McClure. 95 percent? Over all of your facilities?

Mr. Boyd. Yes. Over the year at any one time, we have 5 percent of our turbines that are not operational.

Senator McClure. Mr. Bazor, what is your on-line availability?

Mr. Bazor. During our peak periods of time in the summer, we are at 100 percent, because bear in mind we do not operate 24 hours a day. We produce most of our power when the utility needs it. We operate about 35, 40 percent of the year, and that gives us a golden opportunity to fix anything when the unit is down. So, we can operate at a very high rate of reliability.

Senator McClure. What kind of things cause your units to go down?

Mr. Bazor. Well, in a power block, just like anything else, a bearing in the turbine, some problem——

Senator McClure. The routine kind of turbine maintenance, but how about in the——

Mr. Bazor. In the solar field——

Senator McClure. In the solar field.

Mr. Bazor. It is things like if we got a tube, one of these tubes lost its vacuum. It is like I say, it is like a thermos bottle. If it loses its vacuum, well, it is not effective. We would have to change that out.

But what we have got is we have got enough segments, we have got this thing segmentized to where we can take small, incremental units out and do the maintenance, while the rest of the field is operating. We designed these things for an optimum power production, in that in the summertime we have got about 10 to 15 percent of the fields stowed so that during, as the season goes on and the sun gets out of focus because of the season, we bring all the field into play and produce more electricity, so we are extremely reliable.

Senator McClure. Well, I am just looking at the problems of maintenance of the system. You talk about the fact that you get better efficiency, the efficiencies of scale because a given number of people can service more units. Now, what kind of service do you do to the units just routinely? You have mentioned the fact you can lose a vacuum in a tube, what else happens? What do you have to do to maintain that field?

Mr. Bazor. To maintain the field, and I do not know whether you classify this under maintenance, but we have field walkers that go by and make sure that we do not have any leaks in our joints, okay. We have mirror washers. We have to wash these mirrors about once every week, or at the outside, every two weeks.

Senator McClure. The wind that helps Mr. Boyd puts dust on your mirrors? [Laughter.]

Mr. Bazor. Yes, sir, to a degree, particularly on the outer limits. We do not suffer that on the interior of our solar fields, but it is more pronounced on the exterior than it is interior. But you would be surprised how it impacts the reflectivity by having a dirty mirror.

Senator McClure. So you monitor for leaks and you wash the mirrors. What else, routinely, do you have to do to maintain that field?

Mr. Bazor. Well, we check out the AC tubes for vacuum loss. We replace them. We replace mirrors that may be broken, and I guess we break about maybe 1 percent a year for some reason or another, replace the mirrors and things of that nature.

Senator McClure. Mr. Sklar, what kind of routine maintenance is found in the photovoltaic fields?

Mr. Sklar. Those that have trackers, there is obviously some tracker maintenance. Mostly, it is cleaning dust off the photovoltaics, no moving parts, connectors once in a while.

Senator McClure. And what is the availability of a solar panel?

Mr. Sklar. Life now is 25 years, pretty much there. Most of the panels are now becoming UL rated, so pretty reliable.

Senator McClure. A much different situation than existed five or 10 years ago?

Mr. Sklar. Yes. We had, 10 years ago, severe lamination problems, where water was getting in between the glass. Degradation on silicon, even your thin film—not your thin film, but your polychrystalline. Degradation problems with single and polychrystalline essentially are not a problem anymore. Encapsulation is not a problem anymore, so there are some real moves in that direction, too.

Senator McClure. Could you give me some idea of the capital costs versus maintenance cost, percentages in the cost of production in a photovoltaic field?

Mr. Sklar. Well, right now, the largest fields right now that we have is with PG&E, and that is a project called PV USA where they have about 200 kilowatts to a half a megawatt of 11 of the top photovoltaic technologies. And right now, of those that have been installed, we have less than 1 percent any problems in terms of maintenance.

Senator McClure. Mr. Boyd, when you look at the price of the electricity, how much of it is represented by capital cost and how much by maintenance?

Mr. Boyd. The maintenance cost runs right now about 15 percent of what we get paid. Capital cost recovery is probably in the order of 70.

Senator **McClure**. Mr. Bazor.

Mr. **Bazor**. Our capital costs are about $2,800 per Kw. Where we get competitive is over the life cycle of the project using sun as a fuel. Our maintenance cost is about seven and half a Kw.

Senator **McClure**. Thank you very much.

The **Chairman**. Gentlemen, I think that is it. Thank you very much for your testimony.

[Whereupon, at 12:22 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

OFFICIAL COMMITTEE FILE
PLEASE RETURN

U.S. WINDPOWER

U.S. WINDPOWER, INC.
6952 Preston Avenue
Livermore, CA 94550
TEL: 415-455-6012
FAX: 415-443-3995

A KENETECH COMPANY

June 14, 1990

1990

The Honorable Bennett Johnson
Chairman - Senate Energy and Natural Resources Committee
SH-136 Hart Senate Office Building
Washington, D.C. 20510-1802

Dear Senator Johnson:

In response to your request to answer an additional question arising out of the committee's May 15 hearing on S.2415, the Solar and Geothermal Power Production Act of 1990 please refer to my supplemental testimony submitted to the committee on May 29, 1990. I believe the question you present was comprehensively discussed in that document.

Thank you again for allowing my comments and for giving S.2415 your thoughtful consideration. If I can provide any further information, please call on me.

Sincerely yours,

Hap Boyd

Robert T. Boyd

HP:jmv

U.S.WINDPOWER

U.S. WINDPOWER, INC.
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A KENETECH COMPANY

May 29, 1990

The Honorable Bennett Johnston
SH-136 Hart Senate Office Building
Washington, D.C. 20510-1802

Dear Senator Johnston:

Thank you very much for allowing me to testify before your Senate Energy and Natural Resources Committee on S 2415, "The Solar and Geothermal Power Production Incentive Act of 1990". I enjoyed giving testimony and appreciated hearing your frank views regarding PURPA.

I realize that you have strong views regarding the mandatory buy and hook-up provisions of PURPA. I would like to offer my comments on those provisions in light of how PURPA is being implemented by the states and why I think they are still needed. I would like to do this by supplementing my original written testimony. My supplementary testimony is attached.

Thank you for your kind indulgence.

Sincerely yours,

Hap Boyd

R.T. Boyd
Director of Regulatory Affairs

RTB:dad

SUPPLEMENTAL TESTIMONY
U.S. WINDPOWER, INC.
TO THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
CONCERNING
S.2415, THE SOLAR AND GEOTHERMAL POWER
PRODUCTION INCENTIVES ACT OF 1990

MAY 24, 1990

PURPA IMPLEMENTATION HISTORY

The passage of the Public Utilities Regulatory Policy Act of 1978 was a revolutionary and far-sighted achievement for the United States. It established the long-range policy for a competitive marketplace in electric power generation.

As with many new laws it took time to bring the intent, the language and the implementation into harmony. At the time the law was passed, many states were heavily dependent on oil as their major source of fuel for electrical generation. As a result of the oil embargo, prices of oil soared and power prices went up accordingly. It was under this scenario that some utilities forecasted their future pricing. These prices were used to make firm price power contracts in which the fixed price extended for 10 years in the future. Looking backward, these price schedules are high compared to current utility costs. However, at the time they were the best estimate of the future.

In California, this type of pricing ended in 1984 when the standard offer number four contract was suspended. Meanwhile in other states, the California experience was being observed and modified. Public Utility Commission looked at PURPA and designed pricing systems which would keep the spirit of PURPA, but would be responsive to market conditions.

The concept that emerged was to have pricing reflect the supply condition of the market. In effect, this sets the price at which a utility will be a willing buyer of power at the energy cost of power - the fuel cost plus operation and maintenance - when no additional generation capacity is required. This represents a utilities indifference point when the cost of power is the same whether they generate it or buy energy from a third party.

To further refine the process a bidding system was initiated under which third party power producers could bid to supply power when a utility decided it needed additional capacity. Here the concept is if the third party can provide capacity at a lower cost than the utility then they should build the plants and the ratepayer will benefit.

What the bidding process has done is to improve upon PURPA. PURPA requires a utility to purchase power at its avoided cost (the cost allocated to the next plant the utility might build). When plants are bid into the system, the price is lower than the utilities long-run avoided cost. If the price is not lower, then the utility will build its own plant (Attachment A).

PURPA's purchase obligation does not create a subsidy for QFS. It helps to create a competitive market.

While the PURPA intent has been incorporated into many states, (27 states either have or are working on a bidding system), many states have not yet effectively dealt with PURPA. When properly implemented, the PURPA law should make ratepayers indifferent as to whether power is produced by a utility or a non-utility generation. Utilities are not indifferent because they only earn a return on utility-owned generation facilities - not on power purchased from independent generators. It is no mystery why many utilities oppose PURPA.

The mandatory purchase requirement is still needed until competitive procedures are instituted in all states. Until competitive market is established throughout the country, some utilities will discriminate against independent procedures by building their own generation regardless of the cost. The ratepayers will suffer because they will not be buying the least cost power provided by a competitive marketplace.

Independent power producers need firm contracts in order to receive long-term financial commitments for their projects. The manditory buy provision gives the financing entity security that the income stream to the project will be certain and the debt will be repaid. The utilities rate of return structure provides this type of security for utility plants in the financial market place. PURPA provides this same type of security for independents.

S.2415 is an important bill because it removes an artificial barrier to economic efficiencies of renewable technologies which can be attained by larger project sizes. This charge is largely technical and brings those technologies into parity with cogeneration.

APPENDIX A

WASHINGTON Post

D4 TUESDAY, MAY 15, 1990

Va. Power To Build New Plant

Utility Also Contracts With 3 Private Plants

From News Services

RICHMOND, May 14—Virginia Power said today it plans to build a 400-megawatt, coal-fired power plant in southern Virginia to meet demand for electricity in the late 1990s.

If approved by the State Corporation Commission, the plant would be built in Mecklenburg, Greensville or Cumberland counties by 1997, the company said.

The utility also announced it would buy about 442 megawatts of electricity from three privately built and operated power plants.

The amount is about 700 megawatts less power than the utility sought to buy from private companies when it asked for bids last year.

Of 78 companies that submitted applications, the three that were chosen were the only ones that could provide power cheaper than Virginia Power could, said utility spokesman Carl Baab.

The State Corporation Commission, the utility's regulator, has launched an investigation into how Virginia Power handles its competitive bidding process, said SCC spokesman Ken Schrad.

"The measuring sticks they use to compare one project against another has been developed by Virginia Power, and while they keep [SCC] staff regularly informed about what they are doing . . . there has never been any kind of formal approval of those benchmarks," Schrad said.

Baab said the bids from cogenerators, which often are companies that make steam for industrial uses and use the excess steam to generate electricity, are analysed "on various factors," including the cost to build and operate the expected life span of the facility and the reliability of the company to provide the power.

Baab said only three projects—a 205-megawatt, coal-gasification cogeneration unit; a 196-megawatt, pulverized coal cogeneration unit; and a 41-megawatt municipal waste-to-energy facility—could provide power cheaper than the utility could build its own plant.

This round of bidding was designed to find power sources for projected 1995-97 electricity needs. Virginia Power expects to need to add 6,000 megawatts of capacity by the year 2000.

Until now, the company has been relying primarily on the private power industry to meet increasing demand.

LUZ INTERNATIONAL LIMITED

June 13, 1990

Senator J. Bennett Johnston
Chairman
Senate Committee on Energy and
Natural Resources
Washington, DC 20510-1802

Dear Senator Johnston:

Thank you for your letter of May 25, 1990 requesting my response to questions arising from the Committee's hearing on S. 2415. I appreciate this opportunity to respond more fully to your concerns regarding legislation to remove the size limit for solar and geothermal facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

In order to respond thoroughly to each of the questions you raise, I would like to respond separately to each issue presented in your question.

I. If the size limitations are lifted, why would the small power producers covered by the bill need any of the attributes of QF status other than the Holding Company Act exemption to succeed?

There are two principal benefits of qualifying status under PURPA: exemption from most federal and state utility type regulation and the opportunity to enter into contracts to sell electricity to utilities at rates which do not exceed a utility's avoided cost.

A. QF's must retain the full exemption from utility regulation presently available under PURPA.

Simply exempting larger solar and geothermal facilities from regulation under the Public Utility Holding Company Act of 1935 ("Holding Company Act") would create a class of qualifying facilities ("QFs") subject to federal and state utility regulation while another class of QFs would not be subject to such regulation.

As your question suggests, exemption from the Holding Company Act is crucial for QF's, regardless of size, due to the impact of the Holding Company Act on our ability to attract private capital to energy projects. We believe it is also critical to exempt QF's from other aspects of utility regulation under the Federal Power Act ("FPA") and state utility laws.

Exposing QFs to the additional burden of state and federal utility regulation would serve only to entangle QFs in regulations specifically designed to deal with the monopoly power of conventional utilities. Such additional regulation could impede the ability of larger solar and geothermal QF's to attract capital and therefore the development of these resources.

In 1978 Congress gave the Federal Energy Regulatory Commission ("FERC") authority to exempt QFs from burdensome state and federal utility regulation. In implementing PURPA, after a detailed analysis, FERC concluded that these exemptions were necessary in order to encourage the development of cogeneration and small power production facilities, the objective of PURPA.

Since the implementation of these exemptions, this approach has not been challenged at FERC. In its recent review of the PURPA program, and in Notices of Proposed Rulemaking arising from that review which are still pending, FERC did not propose that exemptions from utility regulation be modified or withdrawn, nor are we aware of any arguments presented to the Commission suggesting such changes.

We believe that it would be inconsistent with the removal of size restrictions for solar and geothermal facilities to at the same time limit the exemptions from utility regulation available. In particular, exposing larger solar and geothermal QFs to utility regulation would place them at a competitive disadvantage compared to other QFs which are exempt from such regulation. The economic viability of solar and geothermal projects is still marginal, and they would be heavily burdened by utility regulation.

1. Regulation under the Federal Power Act

Under current law and regulations, QF's are not subject to utility type regulation under the FPA. If they were subject to regulation under the FPA, solar and geothermal facilities would be exposed to substantial additional regulatory burdens and restrictions. They would be required to make rate filings at FERC, and FERC would be authorized to conduct evidentiary hearings to determine whether rates are just and reasonable or unduly discriminatory or preferential, to set rates under the just and reasonable standard and to order refunds of amounts collected above just and reasonable rates. This would effectively give FERC responsibility for oversight of rates paid to such QFs, either duplicating the present responsibilities of the states under PURPA or transferring such authority from the states to FERC. In either case, this would radically alter the

PURPA program in a manner inconsistent with allowing larger solar and geothermal QFs to compete with other qualifying facilities which are exempt from the FPA.

Regulation under the FPA would also substantially restrict the business activities of solar and geothermal facilities. QFs would be required to gain prior approval from FERC regarding the disposition of jurisdictional facilities, issuance of securities, assumption of liabilities, mergers and interlocking directorates. In addition, they would required to maintain their books and records according to the complex Uniform System of Accounts, designed solely to assist FERC in the determination of rates for utilities.

Exposing larger solar and geothermal facilities to regulation under the FPA would introduce significant risk and uncertainty to a business environment which is now predictable. Such a change would make it very difficult to attract private capital to larger solar and geothermal projects, particularly when other projects could continue to offer investment opportunities in QFs not subject to this regulation.

2. State Utility Regulation

The current PURPA exemption from state utility type regulation reflects the traditional differences between third party generators and electric utility companies. While QF's are exempt from regulations intended to govern such issues as a utility's financial organization, they are subject to siting requirements and environmental review, as well as state review of power purchase agreements under their delegated authority to implement PURPA's regulations.

Eliminating PURPA's exemption from state utility type regulation would open up the possibility of exposing solar and geothermal facilities to additional regulatory requirements, unrelated to their activities, respecting rates, accounts and corporate activities. As with regulation under the FPA this would place larger solar and geothermal QFs at a disadvantage compared to other QFs which are exempt from state utility regulation.

Under the best of circumstances, each state would separately have to recreate a form of the PURPA exemption in order for larger solar and geothermal facilities to be exempt from inappropriate state utility regulation. Under the worst of circumstances, some states would leave in place burdensome regulations designed for traditional utility regulations.

Moreover, depending on state law, either legislation or lengthy regulatory procedures may be required to make these changes. Changing this aspect of the PURPA program would serve only to create uncertainty and would diminish rather than expand the market opportunities available to solar and geothermal facilities.

B. The structure of the PURPA program must be preserved to prevent ambiguity regarding the status of QF contracts.

Before the enactment of PURPA, states could not constitutionally approve rates for interstate wholesale sales of electricity. Title II of the FPA, enacted in 1935, established federal regulation over sales for resale in interstate commerce and gave the Federal Power Commission authority to approve such sales contracts, thereby statutorily preempting state activity in this area.

Congress and FERC delegated much of the authority to implement the PURPA program to state regulatory bodies, and states derive their authority to approve or disapprove QF sales contracts from this delegation. Removal of the federal delegation to the states, particularly if the FPA exemptions in PURPA were also eliminated for solar and geothermal facilities in excess of 80 megawatts, would transfer administration of the program from the states to FERC. This would create tremendous uncertainty about the standard for contract approval and how contracts between utilities and larger solar and geothermal facilities would be treated when compared to QF contracts which would remain subject to state review.

With respect to non-utility generation, it does not seem logical for states to regulate facilities of 80 megawatts or less and for the federal government to regulate facilities over 80 megawatts, and for potentially different standards to govern state and federal review. A similar situation occurred when Congress extended a Holding Company Act exemption to biomass facilities of 80 megawatts or less but limited the FPA exemption to biomass facilities of 30 megawatts or less. FERC has responded by granting administrative waivers of the FPA, but such an administrative remedy is more costly and cumbersome than a clear statutory standard, and appears to serve no public purpose.

II. In particular, why would the mandatory purchase provisions of section 210 of PURPA be necessary?

It has always been difficult to evaluate the importance of the mandatory purchase provisions of section 210. As utilities gain experience in evaluating the real benefits associated with purchases from QFs, as measured against other bulk power purchases from utilities or self-generation, and as they move towards competitive resource acquisition policies, the significance of the mandatory purchase is diminishing and becoming even more difficult to evaluate. Even if the mandatory purchase is no more than an obligation for utilities to consider QFs when making resource decisions, it is of value, particularly for a new technology and in service areas where utilities have not yet gained experience and comfort with third party generation.

Modifying or eliminating the mandatory purchase provisions for solar and geothermal facilities of more than 80 megawatts could result in disfavoring these technologies, particularly if present law remains unchanged with regard to other QFs, including cogeneration which is not subject to a size limit. Even if Congress does not intend for such discrimination to occur, the reaction of financial markets and utilities making choices between various potential power suppliers could produce this result.

If Congress should make the public policy decision to modify the mandatory purchase provisions as they apply to otherwise qualifying solar and geothermal facilities over 80 megawatts, we would strongly urge that such an approach be narrowly crafted in a manner which would not alter other integral features of the PURPA, including the ability of the states to administer the program.

III. Doesn't this imply the possibility of subsidy?

PURPA provides certain benefits to technologies which Congress decided in 1978 to encourage in order to promote the diversification of U.S. energy resources. At least with regard to solar and geothermal facilities, Congress appears to continue to support encouragement of these cost competitive technologies, which are generally regarded as non-polluting.

These benefits include exemption from burdensome utility regulation designed to address the market power of conventional utilities, and the ability to sell power to utilities. These benefits are appropriate, and they are not a subsidy.

The mandatory purchase does not provide a subsidy, nor does it provide authority for a subsidy to be given. To the contrary, PURPA specifies that rates are not to exceed the incremental cost to a utility of alternative electric energy. The PURPA regulations specifically state that if utilities do not have a need for capacity, they are not required to make capacity payments to QFs. Nor does PURPA authorize payment for energy at a rate which exceeds the incremental cost of alternatives otherwise available to utilities. FERC regulations state that, if a utility does not avoid energy costs by purchasing power from a QF, it is not required to make energy payments to QFs.

In states with active PURPA programs -- which are also the states where utilities generally have a need for new energy and capacity -- utilities and their state regulatory commissions are moving rapidly towards competitive procurement procedures to determine appropriate power purchase rates. Many factors in addition to price enter into the evaluation by utilities of power supply proposals, including load tracking, reliability, environmental impact, diversity of fuel mix, insulation from price shocks and efficiency of use of local resources.
As a result, as with their own resource decisions, utilities may choose not to award contracts to a low bidder, because a higher bidder may present an overall proposal that is more consistent with the utility's needs and other policy objectives which govern resource decisions.

With increasing reliance on competitive selection processes to award QF contracts, healthy market forces are driving prices down and the most reliable and appropriate resources are being chosen at prices which provide significant ratepayer benefits.

Thank you again for the opportunity to appear before the Committee last month and for this opportunity to further comment on S. 2415.

Sincerely,

James Bazor

JB/ss

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June 20, 1990

Bill Conway
Senior Counsel
Senate Energy and
  Natural Resources Committee
364 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Bill:

Pursuant to our recent conversation, I am submitting for the committee hearing record, California Energy's written response to Chairman Johnston's questions.

If the committee needs any additional materials or has questions about any of the issues contained in this submission, please do not hesitate to contact us.

We appreciate your attention to this very important issue and stand ready to assist in any way.

Sincerely,

Bruce

Bruce Lehman

/dsh
Enclosure

THE MANDATORY PURCHASE AND INTERCONNECTION REQUIREMENTS OF THE PUBLIC UTILITY REGULATORY POLICIES ACT AND GEOTHERMAL POWER PRODUCTION IN CALIFORNIA

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THE MANDATORY PURCHASE AND INTERCONNECTION REQUIREMENTS OF THE PUBLIC UTILITY REGULATORY POLICIES ACT AND GEOTHERMAL POWER PRODUCTION IN CALIFORNIA

I. EXECUTIVE SUMMARY

The mandatory purchase and interconnection requirements of PURPA have successfully assisted the development of alternative technologies for producing energy, such as geothermal power production. Today, projects employing alternative technologies can offer clean, reliable, and inexpensive energy. Geothermal producers, in particular, can provide a cost-competitive alternative to energy produced from fossil fuels, especially if there is no restriction on the size of the project like the current statutory eighty megawatt ceiling. The mandatory purchase and interconnection requirements are necessary to ensure the continued viability of small power producers and cogeneration projects.

Although there is some concern that the mandatory purchase requirement will lead to subsidization of qualifying facilities, the regulatory processes in California are designed to eliminate any significant risk that power from qualifying facilities will be overpriced or that utilities will be forced to purchase unneeded electricity. To the extent that high pricing may have occurred in the past, it resulted directly from projected oil prices in the mid-1980s, which failed to anticipate the sudden drop in prices later in the decade. No reasonable basis exists for fearing a recurrence of these circumstances. Therefore, there is no reason to retract the mandatory purchase requirement for geothermal and solar power producers -- especially while it is arbitrarily retained for all other qualifying facilities.

Moreover, the mandatory purchase requirement plays a necessary role in the maintenance of qualifying facilities: the mandatory purchase requirement drives the state's regulatory processes. The state's processes are necessary to balance any tendency utilities may have to not deal with small power producers and independent cogenerators, despite their cost-effectiveness. Without the mandatory purchase and interconnection requirements, the existence of a diverse and competitively priced supply of energy will be threatened, defeating the objectives of PURPA.

II. BACKGROUND: THE AMENDMENT OF THE PUBLIC UTILITY REGULATORY POLICIES ACT

The Public Utility Regulatory Policies Act ("PURPA") of 1978 promotes the growth of competitive, environmentally benign, diverse sources of energy. Because of the incentives provided by PURPA, many cogeneration and small power producer projects have been initiated. However, the provision's eighty megawatt restriction on qualifying facilities ("QFs") has discouraged and continues to discourage potential projects, with no apparent gain accruing from the restriction. The legislative history reveals no purpose for the limitation. Recognizing that the eighty megawatt restriction unnecessarily thwarts the attainment of PURPA's goals, several members of Congress have recently expressed their support for an amendment that would eliminate the restriction on geothermal and solar facilities.

In the context of amending PURPA, the issue has been raised whether the mandatory purchase and mandatory interconnection requirements of PURPA ought to be eliminated for geothermal and solar facilities. The underlying concern is a fear that public utilities commissions will set unreasonably high mandatory prices for the energy, creating a subsidy for these technologies. This concern is unfounded. Although critics of the mandatory purchase requirement have attributed artificially inflated prices to the requirement, those criticisms are overstated and, in any event, are no longer relevant given the regulatory conditions that exist today. Rather, as a producer of geothermal energy, California Energy Company, Inc. ("California Energy") can and will provide utilities with a cost-competitive alternative to energy generated from fossil fuels. Regulatory processes in California have evolved which will ensure the implementation of those competitive prices, so long as the regulatory processes continue to be driven by the mandatory purchase requirement. The competitive position of geothermal producers will likely decline, however, if the mandatory purchase and interconnection requirements of PURPA are selectively eliminated for geothermal and solar facilities. Those requirements are necessary to offset any incentives that utilities may have to not deal with small, new projects or independent cogenerators. Utilities may tend to prefer projects which are larger or more traditional, projects which they own, or projects in which they have a financial interest, even if the smaller, renewable resources facilities are otherwise preferable. The mandatory purchase and interconnection requirements place independent cogenerators and small power producers back on an equal competitive basis with utility-invested or centralized facilities.

The purposes of this paper are fourfold: first, to show that geothermal energy is already a cost-competitive source of energy and will be even more competitive once the eighty megawatt restriction is lifted; second, to expose the unjustifiable harm that would flow to geothermal and solar power producers if an amendment eliminated the mandatory purchase requirement for those two classes of QFs while retaining it for other QFs; third, to describe how, despite concerns raised regarding the application of the mandatory purchase requirement in the past, major changes in the regulatory process will ensure competitive pricing of contracts for limited quantities of geothermal energy in the future; and fourth, to demonstrate that the mandatory purchase requirement is essential to the survival of geothermal power producers and to the existence of overall least cost resource planning in California.

In sum, a review of the history and current status of regulation in California will show that the public utilities commissions will not set mandatory prices at non-competitive levels in the future, and, quite the opposite, that the mandatory purchase requirement is an essential component of the cost minimization scheme in California. This analysis ought to allay any fear that geothermal energy is not competitive or that the mandatory purchase requirement will create a windfall for its producers.

III. RESPONSES TO CONCERNS

A. Geothermal energy is already a cost-competitive source of energy and will be even more competitive once the eighty megawatt restriction is lifted.

Geothermal power producers like California Energy are capable of providing energy cost-competitive with other technologies, provided the eighty megawatt restriction is lifted. A study conducted by the California Energy Commission ("CEC") in 1989 showed that, assuming no artificial restriction regarding project size, geothermal energy is cost-competitive with energy from other major sources and, indeed, is significantly less expensive than many resources evaluated by the CEC.[1] While the results of the study are already extremely favorable to geothermal power production, the study was based on two conservative assumptions that rendered the calculated cost of geothermal energy higher and less competitive than it likely is in fact. First, the study is based on a conservative forecast of fossil fuel prices. If fossil fuel prices were to increase more rapidly, the potential cost advantages associated with geothermal energy, which tends to not fluctuate significantly in price, would increase significantly Second, in order to facilitate comparison across technologies, the study assumed that all of the facilities evaluated, including geothermal facilities, would operate at a seventy-five percent capacity factor. In fact, California Energy's geothermal facilities have consistently operated at a capacity factor of approximately ninety percent after initial startup. Assumptions regarding capacity factor are particularly critical in evaluating the cost effectiveness of geothermal, since the additional output obtained from operating a geothermal plant at a higher capacity factor, unlike the incremental output from most other energy sources, is essentially cost free. Using a higher capacity factor alone would account for approximately a two cent per kilowatt-hour price decrease in the projected cost for geothermal power -- a striking twenty-two percent of the cost estimated in the study.

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[1] State of California Energy Resources Conservation and Development Commission, "Technology Characterizations," October 1989 (submitted in the matter of Preparation of the 1990 Electricity Report (ER 90), Docket No. 88-ER-8)

Further, the methodology used by the Commission does not account for any value derived from the environmental benefits of geothermal power. Nor does it account for the absence of any risk of significant price fluctuation associated with geothermal energy. Once the geothermal facility is completed and tested, the cost for the fuel source, natural steam, is essentially fixed. In this way, geothermal energy is superior to most of its competitors, the cost for which may escalate sharply depending upon future trends of fuel prices. These benefits can be maximized, however, only if the eighty megawatt restriction is removed.

The ability of producers of geothermal energy, such as California Energy, to offer electricity at even more cost-competitive prices depends in part on Congress' willingness to eliminate the eighty megawatt restriction. Currently, producers may not derive the benefits of economies of scale because of the arbitrary statutory limitation, even though the technology supports production greater than eighty megawatts. Operation on a larger scale would reduce costs of production, thereby enabling producers to offer electricity at even more competitive rates than currently achieved. If permitted by Congress, California Energy is prepared to increase production immediately at its existing facilities, where it is currently throttling back equipment and leaving natural steam in the ground. This energy, if it were produced, could be sold at as low a rate of 3.5 cents per kilowatt-hour.

The eighty megawatt restriction not only requires producers to suppress production at existing facilities but also effectively precludes development of new projects. Studies show that, technologically, geothermal energy can be the most economical source of energy for the future. Even without elimination of the eighty megawatt restriction, geothermal energy already can compete with the most economical sources of energy today.

B. Unjustifiable harm would flow to geothermal power producers if the mandatory purchase requirement were eliminated for them while retained for other qualifying facilities.

If the mandatory purchase requirement is to be amended at all, it would be unreasonably discriminatory to eliminate it for one category of QFs, geothermal and solar power producers, while retaining it for all other categories of QFs. There is no sound policy reason to treat these two classes of QFs differently from others. Such a provision would run counter to one aim of the PURPA amendment: to eliminate an arbitrary provision, i.e., the eighty megawatt restriction. By retracting the mandatory purchase and interconnection requirements for only limited classes of qualifying facilities, Congress would merely replace one arbitrary provision with another.

Furthermore, by differentiating among QFs, Congress would place geothermal power producers at a competitive disadvantage with other QFs by unequally depriving them of benefits of PURPA. The harm from such discrimination would be extremely detrimental to geothermal producers and is not justified by any legitimate legislative objective. Geothermal producers do not seek special treatment from other QFs. They seek only to compete on an equal basis with other QFs, under the same ground rules.

C. Despite concerns raised regarding the application of the mandatory purchase requirement in the past, major changes in the regulatory process ensure controlled quantities and competitive prices for electricity from qualifying facilities in the future.

Critics of the mandatory purchase requirement contend that the requirement forces utilities to purchase electricity at uncompetitive rates, resulting in a subsidy to QFs. Although in the mid-1980s the California Public Utilities Commission ("CPUC") applied the mandatory purchase requirement in such a way that led critics to fear abuses of the provision, there is no reasonable basis for believing that there will be abuses in the future. There are at least two significant differences between the conditions under which the mandatory purchase requirement was applied in the mid-1980s and the conditions under which the requirement will be applied in the future. First, factors specific to the 1980s, which are not present today, contributed to a large supply of QF electricity at relatively high prices. Second, major changes in the regulatory process ensure that in the future utilities will be required to purchase electricity from QFs only when there is a demonstrated need for capacity and only when the price of the electricity is equal to or less than the utility's least cost alternative option.

1. Conditions specific to the early 1980s and not applicable today are responsible for the past flood of supply of electricity at relatively high prices.

When PURPA was enacted in the early 1980s, the CPUC had no experience on which it could rely to develop a program under PURPA that would adequately anticipate the demands that would be placed on the program. Furthermore, prices of oil and gas declined unexpectedly and dramatically in the mid-1980s, shattering the underlying assumptions the CPUC used to implement PURPA. As a result of these two conditions, utilities were faced with a large supply of electricity from QFs at high prices relative to the new, equilibrium prices of energy alternatives. Unlike in the mid-1980s, today the market for oil and gas has been relatively predictable, and the CPUC has had ample experience with PURPA and has developed elaborate procedures for implementing its provisions in a controlled manner. Therefore, the CPUC's experience with QFs in the early 1980s provides no legitimate basis for fearing that utilities in the future will be forced to purchase electricity at unnecessarily high prices.

In the mid-1980s, the CPUC established an interim standard offer, Interim Standard Offer Four ("Interim SO4"), to facilitate implementation of PURPA while a major regulatory program was being developed. To establish the terms of Interim SO4, as with any standard offer, the CPUC needed to determine the utility's avoided cost. By its nature, the determination of avoided cost requires making factual assumptions, on which projected costs are based. These estimates are, of course, inexact approximations of future events. Because of the inherent uncertainty in the utility power planning process, in an after the fact prudence review, the reasonableness of a utility's decisions are judged against a standard which accounts for the reasonableness of the assumptions given what the utility knew at the time of the decision, notwithstanding the ultimate accuracy of the assumptions. The process for developing the price terms of Interim SO4 was completely consistent with general utility planning principles.

Despite the reasonableness of the CPUC's assumptions, in the case of Interim SO4, the CPUC based its determination of price levels on projections of oil prices which were ultimately higher than the actual prices. At the time, oil prices had been escalating sharply, and it was universally believed that they would continue to escalate. Among the oil projections forecasted by analysts, the CPUC chose a conservatively low one as its basis for calculating avoided cost in Interim SO4. This projection was reasonable -- indeed cautious. Like virtually all oil price forecasts developed during the time period, however, the forecast relied upon by the CPUC later proved to be high. The change in oil prices, against which competitor sources were compared, made the standard offer price seem high.

A second unexpected event contributed to the conditions which utilities faced in the mid-1980s. PURPA generated enormous interest from potential developers, to the surprise of even its proponents. An overwhelming number of new projects were proposed, often referred to as the "gold rush." No one, including the CPUC, had anticipated such an extraordinary response to the program. Measures to implement PURPA had not been developed to manage the large number of proposals, and the CPUC was naturally without experience on which it could rely. Ultimately, there was a large supply of electricity, which the utilities were required to purchase.

The CPUC was extremely sensitive to criticisms that it was not properly prepared to manage the wave of responses. The CPUC responded swiftly by bringing the standard offer process to a virtual halt, which has now been in effect for over five years. In April 1985, the CPUC suspended Interim SO4, approximately one and a half years after it became effective, and in 1986 the CPUC suspended Standard Offer 2 ("SO2").

Even though Interim SO4 permitted relatively high prices, only a limited number of projects materialized. The only projects that have gone forward under Interim SO4 contracts were those entered during the short span of Interim SO4's existence, prior to April 1985. Many of the projects that received Interim SO4 contracts did not meet the five year on-line requirement and therefore never came to fruition. For those projects that did go forward pursuant to Interim SO4, prices nonetheless have proved to be competitive with those of other generating sources added in California during the same time period.

The history of Interim SO4 shows that because of conditions in the 1980s, namely, the CPUC's lack of experience with PURPA and the universal projection that oil prices would remain high, the CPUC may have applied the mandatory purchase requirement in a way that ultimately, though unforeseeably, led to an excess of supply at relatively high prices. However, it would be improper to generalize about the mandatory purchase requirement beyond the narrow circumstances of that particular application. Moreover, the CPUC has developed procedures since then which wholly eliminate any appreciable risk that the mandatory purchase requirement will be applied unfairly in the future.

2. The California Public Utilities Commission has developed and implemented mechanisms for control over standard offers which ensure that mandatory purchases in the future will be limited to needed capacity at competitive prices.

As a direct result of the gold rush and the subsequent standard offer suspensions, the CPUC has carefully and deliberately proceeded to develop and implement rules that will control new standard offers and will promote overall resource planning in California. The CPUC's approach will be implemented to ensure that any offer to purchase electricity from a QF will be limited in amount to the demonstrated need for capacity and limited in price to the cost of the least cost resource available to the utility. As a result, no utilities will be "forced" to purchase electricity at uncompetitive rates.

The CPUC has already demonstrated its conservative approach toward applying the mandatory purchase requirement. By suspending Interim SO4 and SO2, the CPUC has effectively refused to allow new contracts with QFs or new QF projects. Interim SO4 and SO2 were the only standard offers that provided for capacity payments. The only standard offer remaining in effect, Standard Offer One ("SO1"), effectively precludes new projects, because, by its terms, SO1 does not provide for capacity payments. Under SO1, the CPUC sets the contract price based solely on the incremental cost for fuel that the utility would burn if it generated electricity on its own, the energy payment. (In recent years, the cost for such fuel has equalled approximately 3.5 cents per kilowatt-hour.) Because these rates give no return for the capacity value of new projects, they are too low to stimulate new QFs. Predictably, therefore, there have been no new projects in California based on the terms of SO1.

While the standard offer program has been inactive over the last five years, the CPUC has undertaken major regulatory reforms. After extensive factual inquiry and analysis, the CPUC has crafted procedures to control the implementation of the program in the future. The CPUC has also refined the terms of Final SO4 and SO2. The new regulatory procedures are structured to bring about the most fair and economical outcome. As a result of the CPUC's efforts, the implementation of standard offers in the future will occur through tightly controlled and well informed processes.

The standard offer program will begin with a careful analysis for each utility to determine whether the utility needs more capacity and, if so, how much. Only if a demonstrated need for capacity in California is established will the CPUC approve a long-term standard offer. Furthermore, a utility is not required to offer to purchase on a long-term basis any more than the maximum number of megawatts the CPUC determines is needed.[3]

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[3] Even if a utility no longer needs new capacity, it will still be required to offer to purchase electricity pursuant to the terms of SO1. However, as discussed earlier, SO1 is premised

(continued...)

That is, the CPUC's determination of megawatts of capacity needed will act as a ceiling on the ultimate quantity term of the contract.

If the CPUC does determine that additional capacity is needed, it will then engage in an intensive analysis of the sources of power available to the utility for the purpose of identifying the least cost source. Such an evaluation will occur in the setting of a full scale regulatory proceeding. The utility will be required to identify all significant potential sources of electricity that could meet its demand and to estimate the cost associated with each resource. Intervenors will have the opportunity to challenge the utility's data and to present their own data. After careful analysis of the data, the CPUC will determine the least cost resource otherwise available to the utility to meet its incremental needs. Once the least cost resource is identified, this cost will serve as the ceiling at which the utility will be required to offer to purchase energy. Through this process, the ultimate price of the contract is certain to be less than or equal to the least cost resource available to the utility.

The utility must then publicly solicit offers to supply power at the ceiling price and megawatt quantity, so that any power producer who can produce energy at a price less than or equal to the least cost alternative may make a proposal. If the offer is oversubscribed, as it likely will be, further rules will govern the utility's selection of a project. The rules will likely prefer projects that offer a price below the ceiling and will allow the utility to take into account other factors, such as the facility's reliability. As a result of this competitive bidding process, the contract price is likely to be significantly lower than the utility's least cost alternative resource.

By allowing utilities to issue new, long-term standard offers only when the projected demand for electricity increases, the CPUC ensures that new projects are encouraged only when there is a demonstrated need and only to the extent new capacity is needed. Therefore, utilities never will be "forced" to purchase unnecessary electricity or to pay artificially inflated prices. Furthermore, when the supply is increased, the price which the utility must pay will never exceed, and will often significantly

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[2] (...continued) on the assumption that no new capacity is needed, and hence the price includes no payment for the value of new capacity. Under these terms, the price is insufficient to induce developers to build new facilities. As a practical matter, therefore, the mandatory purchase requirement will not force a utility to purchase unneeded electricity from QFs, because no QF will accept the utility's offer when the utility does not need capacity.

undercut, the cost of the cheapest available alternative to meet the utility's demand.

D. The mandatory purchase and interconnection requirements of the Public Utility Regulatory Policies Act play an essential role in the continued viability of geothermal facilities in California.

Notwithstanding other incentives for geothermal producers provided by PURPA, they likely will not survive without the continued benefits of the mandatory purchase and interconnection requirements. It is important to note that geothermal and other small power projects not owned by utilities have never gone forward in California without the mandatory purchase requirement in effect. Historically, the mandatory purchase requirement triggered the regulatory programs without which QFs would not have developed as competitive technologies. Today, the mandatory purchase requirement drives the CPUC's inquiry into the need for capacity in California and the least cost sources available to utilities. There is a clear risk, therefore, that if the mandatory purchase requirement is eliminated, these programs will disappear. Such a result would severely undercut the competitive position that geothermal and other newer technologies have achieved and would likely preclude new projects from proceeding.

While the technologies of renewable resources in California have progressed remarkably, there is still reason for concern that there may be resistance to such projects, even when they can convincingly demonstrate their cost-effectiveness. Utilities may prefer to build their own generation facilities, even when geothermal projects can produce power at lower cost. Some utilities have significant financial interests in cogeneration subsidiaries or proposed projects, which they would inevitably favor over independent projects. Others may prefer to deal with more traditional facilities rather than the newer renewable resource technologies. Another disincentive for utilities to deal with renewable resources is that the utility must decentralize its source of generation across several, smaller facilities rather than contracting with one or two large, centralized units. For these reasons, there is a continuing risk that utilities will prefer not to deal with smaller renewable resource projects, even when those projects could play an essential role in the utility's least cost resource planning.

The only effective way to insure against these pressures is to maintain the mandatory purchase and interconnection requirements. The requirements neutralize any bias that the utilities may have toward traditional generation stations by allowing cost-competitive renewable resources to compete. There is no sound reason to remove the requirement for geothermal or solar facilities, especially while it remains in effect for all other QFs. Moreover, the layers of regulatory checks now established provide every assurance that the requirements will apply only when the technologies can fully demonstrate their competitiveness and when utilities show the need for additional power.

Question For The Hearing Record
From Senator Johnston
S. 2415

1) The proponents of S. 2415 assert that small power producers covered by the bill would be able to generate power at competitive prices if the existing size limitations under PURPA are lifted. If the size limitations are lifted, why would the small power producers covered by the bill need any of the attributes of QF status other than Holding Company Act exemption to succeed? In particular, why would the mandatory purchase provisions of section 210 of PURPA be necessary? Doesn't this imply the possibility of subsidy? Please provide a detailed response.

Department of Energy
Washington, DC 20585

AUG 17 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On May 25, 1990, J. Michael Davis, Assistant Secretary for Conservation and Renewable Energy testified before your committee on S. 2415, the Solar and Geothermal Power Production Incentives Act of 1990.

Following that hearing, you submitted written questions to be provided for the record. Per your request, we have enclosed responses to those questions.

If you have any questions, please have your staff call Valerie Howard on 586-2032. She will be happy to assist you.

Sincerely,

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental Affairs

QUESTIONS FROM SENATOR METZENBAUM

Photovoltaics

Question 1: What is the current status of the Photovoltaic Concentrator Initiative (PCI)?

Answer: DOE has authorized Sandia National Laboratories (Sandia) to develop and administer the Photovoltaic Concentrator Initiative, which is designed to accelerate the achievement of the PV program's near-term (mid 1990's) cost goal of $0.10 - 0.15/kWh. Sandia has issued a Request For Quotes, received proposals, evaluated them, and expects to have all contracts placed in June and July. The Photovoltaic Concentrator Initiative Program is designed to stimulate the eventual commercial development of PV concentrator collector systems. The principal mechanism will be cooperative, multi-year, cost-shared programs with industry. The commercialization process for photovoltaic concentrator collectors is the same as that of any private sector developmental program leading to a consumer product: research, engineering and test, and product development, production and distribution.

Prepared by: Robert L. San Martin
Date: 7/11/90
Coordinated with:
Reviewed by: J. Michael Davis, P.E.
Assistant Secretary
Conservation and Renewable Energy

QUESTIONS FROM SENATOR METZENBAUM

Photovoltaics

Question 2: At what level do you intend to fund the program in FY 1991 and beyond?

Answer: We are committing $1.3 million in FY 1990 and expect to spend approximately $3 million each year over the next 3 1/2 years. This funding represents only the government share. Additional support is expected from industry through cost sharing. It is also expected that as the technology matures to the point that demonstration projects are warranted, utilities will financially participate in their funding. Because near-term utility applications exist which can be satisfied by less cost-effective photovoltaic systems, DOE has established a near-term (mid-1990s) cost goal of $0.10 - 0.15/kWh. One of the most promising approaches to achievement of this near-term goal is through the development of photovoltaic concentrator collector systems.

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Conservation and Renewable Energy

QUESTIONS FROM SENATOR MCCLURE

PURPA

Question 1: Please describe the PURPA avoided cost and mandatory purchase requirements, and summarize the regulations implementing those provisions. Please provide the Committee a copy of those regulations and the associated regulatory preambles.

Answer: AVOIDED COST

Section 210 (b) of the PURPA statute requires an electric utility to offer to purchase electricity from qualifying facilities (QFs) at rates that are:

(1) just and reasonable from the standpoint of electric utility consumers and in the public interest;

(2) nondiscriminatory;

(3) not to exceed the utility's avoided cost.

The PURPA statute further defines incremental or avoided costs (Section 210 (d)) as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." Consistent with these statutory provisions/guidelines, FERC implementing regulations (18 C.F.R., Section 292.101 (b) (6) (1987)) look upon avoided costs as the incremental costs associated with utility acquisition of either electric energy or electric capacity or both "which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."

MANDATORY PURCHASE

Section 292.303 of the FERC implementing regulations states that "each electric utility shall purchase, in accordance with Section 292.304, any energy and capacity which is made available from a QF:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section (paragraph (d) spells out FERC requirements concerning "transmission to other electric utilities").

NOTE: Please refer to attached FERC implementing regulations and associated regulatory preambles.

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unless a written extension is submitted to the party requesting the information on one of the grounds enumerated in 5 U.S.C. 552(a)(6)(B). Since providing ten days notice to the party submitting the information is not one of the enumerated grounds for extending the ten day period for divulging the information, the notice period will remain five days. However, the Commission agrees that § 275.206(b) should provide for notice by telegram, and the rule will have been amended accordingly.

The Commission Orders

The Application of Indicated Producers for rehearing of Order No. 34 is granted in part and denied in part.

(Natural Gas Act, as amended, 15 U.S.C. § 717, Department of Energy Organization Act, 42 U.S.C. § 7171, Natural Gas Policy Act of 1978, 15 U.S.C. § 3301)

For the reasons set forth above, the regulations of the Commission are amended as set forth below, effective for protests and FOIA requests filed thirty days after the issuance of this order.

By the Commission.

Kenneth F. Plumb,
Secretary.

[¶ 30,134]

45 F. R. 17959 (March 20, 1980)

18 CFR Part 292

[Docket No. RM79-54]

Small Power Production and Cogeneration Facilities—Qualifying Status

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 201 of the Public Utility Regulatory Policies Act of 1978. These rules set forth criteria and procedures by which small power producers and cogeneration facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA, which were issued on February 19, 1980 (45 FR 12214, February 25, 1980).

EFFECTIVE DATE: March 13, 1980.

FOR FURTHER INFORMATION CONTACT:

Ross Ain, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8446.

Bernard Chew, Office of Electric Power Regulation, 400 First Street, NE., Washington, D.C., (202) 376-9264.

James Liles, Office of Regulatory Analysis, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-8158.

Adam Wenner, Office of the General Counsel, 825 North Capitol Street, NE., Washington, D.C. 20426, (202) 357-9338

SUPPLEMENTARY INFORMATION:

March 13, 1980.

Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that the Federal Energy Regulatory Commission (Commission) prescribe rules under which small power production facilities and cogeneration facilities can obtain "qualifying" status, and thus become eligible for the rates and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

Section 201 of PURPA[1] defines a "small power production facility" as a facility which:

> (1) Produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and
>
> (2) Has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts.

A cogeneration facility is defined as a facility which produces electric energy and steam or forms of useful energy

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[1] Section 3(17)(A) of the Federal Power Act.

(such as heat) which are used for industrial, commercial, heating, or cooling purposes.[2]

Thus, cogeneration facilities simultaneously produce two forms of useful energy, namely electric power and heat. Cogeneration facilities can use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. By using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities as defined in the Act use biomass, waste, or renewable resources, including wind, solar energy and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA, and to provide back-up power and other services to such facilities on a non-discriminatory basis. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act. Finally, under section 206(c)(3) of the Natural Gas Policy Act of 1978 (NGPA), the Commission may exempt qualifying cogeneration facilities from the incremental pricing program under Title II of the NGPA.

In this rulemaking, the Commission sets forth requirements for qualifying cogeneration and small power production facilities and procedures by which such facilities may obtain qualification. Rules implementing section 210 of PURPA have been prescribed in Docket No. RM79-55.[3]

Any qualifying facility is eligible for the exemptions set forth in Subpart F of this part of the Commission's regulations immediately upon issuance of these rules. With regard to the rate benefits for qualifying facilities found in Subpart C of this part, however, the statute provides that the State regulatory authorities and nonregulated electric utilities will have up to one year to implement the Commission's rules. Therefore, the latest date by which qualifying facilities will be eligible to receive these PURPA-derived rate benefits is February 19, 1981.

I. Procedural History

On June 27, 1979, the Commission issued proposed rules in this docket[4] to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 of PURPA.

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[2] Section 3(18)(A) of the Federal Power Act.

[3] 18 C.F.R. Part 292, Subparts A, C, D and F; 45 FR 12214 (Feb. 25, 1980).

[4] 44 FR 38872 (July 3, 1979).

Public hearings on RM79-54 were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking Under Section 210 of PURPA in Docket No. RM79-55.[5] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79-54 and RM79-55.

In a Request for Further Comments,[6] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested persons, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York City on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment. All of the comments were considered in the formulation of this final rule.

II. Summary

These rules set forth criteria and procedures by which cogeneration and small power production facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing section 210 of PURPA.

The rules in this docket permit qualification without a need for specific Commission action. They also make available an optional procedure under which, should it prove desirable, a facility can gain certification as a "qualifying facility." For qualifying small power production facilities, the efficiency standards contained in the proposed rule have been eliminated, and the permitted level of oil, natural gas and coal use for startup, testing, flame stabilization, and operation during outages of the primary energy supply system has been increased and the form of that requirement has been simplified. For qualifying cogeneration facilities, efficiency standards still must be met by certain new facilities using oil or gas. In addition, certain operating standards have been adopted for purposes of assuring that a qualifying cogenerator is a *bona fide* cogenerator.

III. Section-by-Section Analysis

§ *292.201 Scope*

Section 292.201 describes the scope of Subpart B of the Commission's rules. Subpart B provides the criteria for and manner of qualification of small power production and cogeneration facilities.

§ *292.202 Definitions*

This section contains definitions applicable to this subpart of the Commission's rules.

Paragraph (a) defines "biomass" as any organic material not derived from fossil fuels. The proposed rule defined "biomass" as plant materials which are obtained from cultivation, or harvested from naturally occurring vegetation without significant depletion of the resource. Commenters recommended that the Commission expand the definition to include any organic material not derived from fossil fuels. The commenters stated that most studies dealing with energy recovery from organic material other than fossil fuels have included municipal (and most industrial) solid waste within the more general category of biomass.

The Commission agrees with the commenters who urged the Commission to expand the scope of this definition. The Commission observes that applying a narrow definition of biomass might hinder development of small power production facilities between 30 megawatts and 80 megawatts in capacity. Use of a definition of biomass which includes by-products of the manufacturing, harvesting, and growing of agricultural products, including wood, will enable a greater number of small power producers between 30 and 80 megawatts to take advantage of the exemption from State law and regulation regarding rates and financial organization of electric utilities and from the Public Utility Holding Company Act, as provided in subpart F of this part of the Commission's rules.

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[5] 44 FR 61190 (Oct. 24, 1979).

[6] 44 FR 61977 (Oct. 29, 1979).

One commenter questioned whether the Commission meant to include peat within the definition of biomass. The Commission wishes to clarify this point by stating that peat is included in the definition of biomass for purposes of this subpart.

Paragraph (b) defines "waste" as any by-product materials other than biomass. In most instances, waste is a by-product of fossil fuels. Examples of waste include petroleum coke, refinery gas, and plastics.

Paragraph (c) defines "cogeneration facility" as equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy.

Several commenters requested clarification of the applicability of the Commission's rules to cogeneration in the residential sector. The issue arises because of the absence of any explicit mention of residential energy use in the statutory language. The Commission's definition of cogeneration facility tracks the statutory language in that residential use is not specifically identified.

The Commission intends that residential sector cogeneration be included. The Commission believes that the phrase "heating, or cooling purposes" applies to any industrial, commercial, or residential heating or cooling purpose. The Commission has not found anything in the legislative history of PURPA which suggests that the terms "industrial" and "commercial" were intended to modify "heating, or cooling". Separate mention of "residential" use is unnecessary because heating and cooling adequately encompass the residential use of thermal energy. In the industrial sector, thermal energy in the form of process steam is used as an input to many industrial processes. The separate identification of industrial and heating uses is necessary since not all industrial uses of thermal energy are for heating or cooling purposes. In addition, in many instances, commercial heating purposes include heating of residential apartment buildings, so that the exclusion of residential heating and cooling from this program would be difficult to accomplish even if such purpose were within the realm of statutory construction.

Sequential Use

Several commenters recommended that the Commission define cogeneration as the "combined" or "joint" production of heat and power. However, the terms "combined" or "joint" production of heat and power do not fully describe the cogeneration process. The final rules contain an explicit requirement for the sequential use of energy in cogeneration facilities. This means that rejected heat from a power production or heating process is used in another power production or heating process. It is precisely this "cascading" use of energy in sequential processes that gives rise to the energy conserving characteristic of cogeneration.

By adding the phrase "through the sequential use of energy" to the definition of cogeneration facility, the Commission makes explicit what was intended in the proposed rule. The discussions in the proposed rule relating to topping and bottoming-cycle cogeneration and the efficiency standards were expressed in the context of sequential use. Many commenters apparently recognized this fact and, in their discussions of alternative efficiency standards, compared hypothetical cogeneration systems to reference cases of noncogeneration, separate production of heat and power. Additionally the explanation of supplementary firing in the proposed rules implied that energy inputs other than supplementary firing would have to flow through both a thermal and a power production process. The explicit mention of sequential use is therefore not a new requirement; it is a clarification of intent.

Several comments filed in this rulemaking in response to the Commission's November 9, 1979 Interim Rule[7] raised questions about how the sequential use concept would apply in certain situations. One commenter noted that many industries commonly route steam directly from their boilers to processes without expansion in a turbine. This practice is simply the raising of process steam; it is not cogeneration. The fact that some other steam from the same boiler is routed to cogeneration equipment does not mean that all steam from the boiler is used for cogeneration. The coincident raising of process steam relates to the cogeneration rules in two ways. First, any energy expended in raising such steam should not be entered into any efficiency calculations. Secondly, natural gas used for raising process steam is not rendered exempt from incremental pricing solely because the boiler may also supply steam for cogeneration.

A commenter also questioned the applicability of the sequential use test to a combustion turbine coupled with a waste heat recovery boiler. The commenter noted that the boiler could not capture all of the heat in the turbine exhaust and thus not all of the turbine's power could be said to be sequential. The Commission does not adopt this interpretation. The high efficiency of combustion turbine/waste heat recovery boilers derives from the fact that a substantial quantity of waste heat is recovered. The Commission does not require that all heat be recovered. Strictly speaking, some of the available thermal energy in a steam turbine cogeneration system is lost (due to pressure drop in piping along with convective and radiative heat losses) before the steam is delivered to a useful process. As long as any applicable efficiency and operating standards are met, the Commission is not concerned with energy losses within the system.

A final issue concerning the definition of a cogeneration facility involves combined-cycle electric generation plants. Such plants burn gaseous or liquid fuels in a combustion turbine and use the turbine exhaust to raise steam. The steam is directed through a fully condensing steam turbine. Only electricity is produced, albeit through the sequential use of energy. The Commission is of the opinion that combined-cycle electric generation plants are not cogeneration facilities, since only one form of energy is produced.

In paragraph (d), the Commission has added the definition of "topping-cycle cogeneration facility" which is a cogeneration facility in which the energy input to the facility is first used to produce power, and the reject heat from power production is then used to provide useful heat.

Paragraph (e) has been added to define a "bottoming-cycle cogeneration facility" as a cogeneration facility in which the energy input to the system is first applied to a useful heating process, and the residual heat emerging from the process is then used for power production.

The Commission has added paragraph (f), which defines "supplementary firing" as an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

The distinguishing characteristic of supplementary firing as defined here is that none of the energy is used sequentially. In topping cycles, supplementary firing is commonly practiced by introducing natural gas or oil into the hot exhaust of a combustion turbine. The turbine exhaust will typically have sufficient oxygen to support combustion of the added fuel.

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[7] Interim Rule for Qualification of Gas-fired Cogeneration Facilities for Purposes of the Incremental Pricing Program, 44 FR 65744 (Nov. 15, 1979)

The resulting heat can either be used directly in a high-temperature direct heat application or used to raise process steam. Supplementary firing is also possible in steam turbine cogeneration facilities, through reheat of steam which exists from a turbine. In all cases, the added energy is not used to produce power as well as useful thermal energy.

In a bottoming-cycle cogeneration facility, supplementary firing can be used to increase the output of the power production equipment by firing additional fuel in the thermal process exhaust. Again, the added energy is not used sequentially for both power production and a thermal process.

Commission recognizes that there will be questions as to the application of the standards of this subpart to complex facilities which may contain combinations of topping and bottoming-cycle cogeneration equipment. The optional procedure for qualification under § 292.207 is available specifically to help any cogenerator who wishes clarification as to whether his facility would qualify.

Paragraph (g) adds the definition of "useful power output" of a cogeneration facility as the electrical or mechanical energy made available for use, exclusive of any such energy used in the power production process. Although electric power output is required of a qualifying facility, any additional mechanical power may be taken into account in determining "useful power output".

Paragraph (h) has been added to define "useful thermal energy output" of a topping-cycle cogeneration facility as the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application.

The proposed rules contained a definition of the "useful energy output of a thermal process." The term was intended to reflect the heat actually used in a thermal process rather than heat made available for use. The proposed term found application in proposed efficiency standards for both topping and bottoming cycles. Only a few commenters mentioned the proposed term, but they did raise serious questions about the feasibility (and desirability) of performing the necessary calculations. It was argued that computation of the "useful energy output of a thermal process" in accordance with the proposed definition would be difficult and would yield unintended results—particularly in the case of bottoming cycles.

The Commission notes that in its final rules the efficiency of bottoming-cycle facilities is evaluated only with respect to supplementary firing. No evaluation of efficiency is now required for the thermal process of a bottoming cycle.

For new topping-cycle facilities burning natural gas or oil, however, the degree to which heat is recovered and put to use remains a concern. The final rules contain a definition of "useful thermal energy output" which eliminates the problems of the proposed terminology. Under the new definition, in the case of industrial or commercial process use of thermal energy, the thermal energy made available for use in the process may be considered useful thermal energy output of a cogeneration facility. Thus an industrial process which uses steam or heat need not be analyzed for the purpose of determining what fraction of the energy delivered to the process is actually put to use.

In the case of space heating and cooling, water heating, and related heating and cooling applications, a cogeneration facility's useful thermal energy output is the energy actually used in the application. For example, a cogeneration facility may consist of a combustion turbine with exhaust heat recovery used for space heating. In this example, the useful thermal energy output would be the heat recovered from the exhaust and actually used for space heating, not all of the heat available in the exhaust.

Paragraph (i) defines "total energy output" of a topping-cycle cogeneration facility as the sum of the useful power output and useful thermal energy output.

Paragraph (j) defines the term "total energy input" as the total energy of all forms supplied from external sources, other than supplementary firing, to the facility.

The total energy input to a cogeneration facility includes all fuels and renewable resources used in the facility. Energy taken from one part of the facility and used in another part of the cogeneration process does not meet the test of being supplied from an external source. For example, boiler feedwater pumping, heating, and deaerating are energy uses internal to the cogeneration facility and are not to be considered as either energy inputs or energy outputs.

The Commission has added the definition of natural gas in paragraph (k) as it is defined in the Natural Gas Act, which is natural gas unmixed, or any mixture of natural gas and artificial gas. This is intended to cover natural gas supplied by any natural gas company as defined in the Natural Gas Act or any distribution company selling natural gas. As a result, the efficiency standards under § 292.205 only apply with respect to the natural gas so defined and do not apply with regard to any synthetic gas which is unmixed in the pipeline, or mixed by the end-user, such as coke oven gas, blast furnace gas, or gas derived from coal or shale oil.

The definition of "oil" has been added in paragraph (1) to mean crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products. This definition does not include refinery-off gas, petroleum coke, or other waste products of the refinery process.

Finally, the Commission has provided in paragraph (m) that, for purposes of this subpart, in the case of energy in the form of natural gas or oil, energy input is to be measured by the lower heating value of such fuel.

In the proposed rules, energy inputs in the form of fossil fuels were to be evaluated in terms of the lower heating value of such fuels. A few commenters took issue with the use of lower heating values and recommended that higher heating values be specified in the final rule.

Lower heating values were specified in the proposed rules in recognition of the fact that practical cogeneration systems cannot recover and use the latent heat of water vapor formed in the combustion of hydrocarbon fuels. By specifying that energy input to a facility excludes energy that could not be recovered, the Commission hoped that the proposed energy efficiency standards would be easier to understand and apply. The Commission also wished to a apply a standard that would be more uniform in the treatment of natural gas and oil. Owing to the difference in chemical composition, more latent, unrecoverable heat is lost in the combustion of gas as compared to oil. The Commission did not wish indirectly to make qualification more difficult for natural gas-fired cogeneration facilities by requiring a higher level of sensible heat recovery.

The commenters opposing the use of lower heating values generally argued that customary practice is to use higher heating values. The Commission does not find this argument compelling. Both heating values of fuels can easily be found in handbooks. Moreover, if a cogenerator wishes to use the higher heating value of fossil fuel inputs for computing efficiency, the Commission has no objection. Any facility qualifying with efficiency so computed would certainly qualify under the more lenient rules set forth. As a result, the Commission does not believe it appropriate to change this aspect of the proposed rule in this final rule.

§ 292.203 General requirements for qualification.

The proposed rule provided that any person seeking qualifying status for a facility had to initiate discussions with the utility with which it wishes to interconnect and file an application with this Commission. The proposed rule set forth the contents of an application for certification which included technical information describing the facility, a summary of discussions required to be held between the applicant and the affected electric utility, and a description of the equity ownership of the facility. In addition, a small power producer was required to provide information about its primary energy source and its location. A cogenerator was required to submit information describing the energy input and output of the facility in both the heat engines and thermal processes.

The majority of comments favored eliminating the filing requirement either for all qualifying facilities or for specific classes of qualifying facilities. Several commenters suggested that the complexity, delays, and uncertainties created by a case-by-case qualification procedure would act as signficant economic disincentive to owners of smaller facilities. Other commenters recommended exempting smaller facilities, such as facilities with an aggregate electrical capacity of up to 250 or 500 kW, from formal filing requirements. A utility [8] stated that the application procedure does not serve any party or the public's interest. This commenter preferred to see regulations on an "exception" basis where the utility, State regulatory authority or other interested party could object to the granting of qualifying status.

The Commission finds substantial merit in these comments. The Commission believes the initiation of purchase and sale arrangements, pursuant to Subpart C of this part of the Commission's rules, will necessitate the flow of information between potential qualifying facilities and affected electric utilities. The Commission therefore notes that the requirements contained in the proposed rule both for discussions between a potential qualifying facility and the utility with which it wishes to interconnect and for the filing of substantial information with this Commission are not necessary.

For example, one commenter [9] suggested modifying the pre-application negotiation requirements to require that an applicant initiate discussions with the utility prior to filing if the cogenerator or small power producer is intending to negotiate an individual contract. However, if the applicant merely wants to establish his eligibility for an already-published rate schedule for qualifying facilities, this commenter claims that there would be nothing to negotiate, and thus no reason to require that discussions be held. It was asserted that notification to the utility at the time of application would suffice in such cases. The Commission believes that this is what would and should happen without any requirement from the Commission. In addition, the Commission believes that, as a practical matter, an electric utility, which is notified by a qualifying facility that it wishes to interconnect with the utility in order that the utility may purchase the power produced by the facility, will need to know the nature of the qualifying facility's expected purchases and sales so as to be able to arrange safe and reliable interconnected operation at appropriate rates.

As a result, the requirement for case-by-case qualification has been eliminated. Section 292.207(a) of this rule provides that any small power production or cogeneration facility which meets the requirements for qualification set forth in that section is a qualifying facility.

However, the Commission has provided an optional procedure in § 292.207(b) of this rule whereby an application for Commission certification of qualifying status may be filed at the discretion of the owner or operator of the facility.

There was some confusion in the comments as to who actually qualifies under this program. The facility qualifies and that entitles the owners and operators of the facility to receive the benefits of qualification under this part. The benefits of qualification under this part, however, are only with respect to the qualifying facility. For example, the owner or operator of a qualifying cogeneration facility is entitled to require the utility to sell power to his qualifying facility in compliance with the terms of § 292.305 as implemented by the State regulatory authority. The owner or operator has no entitlement to require such rate treatment for the utility's sales to other facilities he may own or operate which are not qualifying facilities. Similarly, his sales to the utility will be exempt under Subpart F of this part from certain Federal and State regulation only to the extent the sales are from a qualifying facility.

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[8] Pacific Gas and Electric Company.

[9] U.S. Department of Energy.

§ *292.203(a) Small power production facilities.*

Section 292.203(a) provides that a small power production facility is a qualifying facility if it meets three criteria.

The first requirement is that the power production capacity of the facility, together with the capacity of any other facilities that use the same energy resource and are owned by the same person and are located at the same site, may not exceed 80 megawatts. The method by which the capacity is determined is described in this preamble under § 292.204.

The second requirement is that the primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof. This means that more than 50 percent of the total energy input must be in these categories. In addition, the aggregate use of oil, natural gas, and coal by the facility may not exceed 25 percent of its total energy input during any calendar year. These fuel use criteria are discussed further in § 292.204(b).

Thirdly, a small power production facility will not be eligible for qualifying status if more than 50 percent of the equity interest in the facility is held by an electric utility or public utility holding company or any person owned by either. Section 292.206 describes this ownership test in greater detail.

One commenter raised the question as to whether a facility is included within the definition of a small power production facility in the statute, and hence the Commission's regulations, if the facility is only part of the process of producing electric energy; namely, raising steam. This commenter produces steam using municipal solid waste, which steam is then sold through an adjoining wall to an electric utility to run through a turbine and produce electricity. In a sense, this facility indirectly produces electric energy. It is unclear to the Commission how this steam-raising facility would benefit from the regulations under section 210. It is not selling electric energy to the utility; it may be buying some electric energy from the utility; and it seems unlikely that it would be subject to electric utility regulation. Therefore, the Commission does not, at this time, see the need to allow qualification for these kinds of facilities, without judging as to whether the Commission could allow such qualification under the statute.

§ *292.203(b) Cogeneration facilities.*

Section 292.203(b) provides that, with the exception of new diesel cogeneration facilities, a cogeneration facility may be a qualifying facility if it satisfies two requirements. First, it must meet the same ownership test as that required for a small power production facility. Secondly, it must meet any operating and efficiency standards described in § 292.205(a) and (b).

In addition, cogeneration facilities which wish to qualify for the incremental pricing exemption permitted under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules must meet the requirements stated in § 292.205(c).

Section 201 of PURPA provides that "a 'qualifying cogeneration facility' means a facility which—(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe * * *". Several comments contended that the statutory language *requires* the Commission to establish standards relating to all of the mentioned criteria. The legislative history of this section indicates that the phrase "as the Commission may * * *" was added in conference; it did not appear in either the House or Senate bill.[10] The plain meaning of the provision, as adopted by the Conferees, is that a qualifying cogeneration facility must meet requirements that the Commission, in its discretion, establishes. These may, but need not, include requirements respecting minimum size, fuel use, and fuel efficiency.

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[10] See Comparative Print to H.R. 4018, Public Utility Regulatory Policies Act. 72, 95th Cong., 2d Sess. (1978).

The Commission received numerous comments from utilities recommending that oil- and natural gas-fired cogeneration facilities not be considered eligible for qualifying status. These commenters generally argued that encouragement of such facilities would be contrary to Congressional intent and national energy policy. Comments were also received expressing strong support for the policy presented in the proposed rule, which did not impose a restriction on oil and natural gas use.

The Commission believes the policy expressed in the proposed rules is consistent with Congressional intent and national energy policy. Had Congress not intended that the benefits of qualifying status be extended to oil- and natural gas-fired cogeneration facilities, the statute or Joint Explanatory Statement of the Committee on Conference (Conference Report) would have contained a restriction on fuel use similar to that which is provided for small power producers. The Congress knew that cogeneration facilities typically use natural gas and oil. In addition, the Natural Gas Policy Act of 1978 contains an express exemption from the incremental pricing program for natural gas used in qualifying cogeneration facilities, which further indicates Congressional recognition that cogeneration facilities use natural gas.

Thirdly, the Congress enacted the Powerplant and Industrial Fuel Use Act (PIFUA) at the same time as PURPA. PIFUA provides authority to the Secretary of Energy to restrict the use of oil and gas in cogeneration facilities. Therefore, the Commission does not believe it necessary or appropriate to require an additional layer of fuel use regulation on technologies which the Commission is charged with encouraging and for which another agency has authority to restrict fuel use.

The Commission also notes that the findings in section 2 of PURPA specifically require "a program providing for * * * increased efficiency in the use of facilities and resources * * *". To the extent that oil- and natural gas-fired cogeneration facilities provide for more efficient use of these resources, the Commission believes that the benefits of qualifying status should be extended to them.

Some of the comments stated that permitting qualifying cogeneration facilities to use oil, especially in diesel engines, will use up available air quality increments, thereby preventing the conversion of large utility oil-fired boilers to coal. As noted above, the Commission believes it is not proper to address this fuel use issue within the context of this program. However, the Commission has not made a final determination regarding the environmental effects of new diesel cogeneration facilities, and is therefore including in these regulations an interim exclusion from qualification of this technology until work on an environmental impact statement has been completed.

§ *292.203(c) Interim exclusion.*

Section 292.203(c) provides that, pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility. A new diesel cogeneration facility is described as a cogeneration facility which derives its useful power output from a diesel engine, the installation of which began on or after March 13, 1980.

Through the issuance of these rules and the rules implementing section 210 of PURPA, the Commission intends to carry out the legislative mandate to provide encouragement to the energy technologies included within the program. The Commission is required under the National Environmental Policy Act of 1969 (NEPA) to take the environmental effects of this encouragement into account. The

Commission has circulated and received public comment on a preliminary Environmental Assessment (EA) of these rules which was issued on October 19, 1979.

(See Appendix I)

Environmental Findings

The identification of the environmental effects associated with a "major Federal action"[11] is not ordinarily a difficult task. These effects typically are those associated with the construction and operation of a particular project in which the Federal government is playing a major role, such as by funding or licensing. In contrast, these rules and the rules implementing section 210 of PURPA do not authorize or fund any particular projects; moreover, they do not authorize or forbid the use of certain fuels. Instead, they provide certain economic incentives to, and remove other disincentives (*i.e.*, assurance of a market for electrical production and exemption from utility regulation) from certain classes of technologies. It is important to note that, even without these rules, these technologies have been, and would continue to be, utilized. The environmental effects associated with this "base-case" level of development cannot be ascribed to these rules. Instead, the proper way to isolate and identify the effects of these rules is to predict the "base-case" (no PURPA) level of development, and determine the environmental effects of that level of development, and compare it to the effects of the projected development with these rules in place. Under this approach, any changes from the base-case review are properly classified as effects of these rules.

The first step used in determining the environmental effects of these rules was to compare, by region, representative electric utility rates with the cost of generating electricity by use of a qualifying facility. This comparison established which technologies would be economically viable. Next, the costs of generating electricity by the facility were compared to an estimate of utilities' avoided costs on a regional basis. If, by receiving the avoided cost for its output, a facility would operate economically, it was considered to have been "PURPA-induced." Avoided cost is the maximum price inducement under this program.

For technologies which would, as a result of PURPA, be economic, regional levels of market penetration were established on the basis of site availability and manufacturing capability. Finally, the environmental effects associated with the predicted level of development were calculated.

The Environmental Assessment accompanying this order describes the environmental effects associated with all of the types of technologies encompassed in section 201 of PURPA. The quantitative effects associated with the predicted market penetration of each technology were then estimated.

The Environmental Assessment includes an extensive market-penetration analysis of each technology eligible for qualification under the Commission's proposed rules and of the aggregate of all of these technologies. Since the proposed rules took the broadest view of which technologies would be eligible for qualification, the analysis covers all technologies, which, under the statute, may be eligible for qualification. On the basis of this analysis, the Commission has estimated the amount of capacity expected to be induced on a regional and national basis through January 1, 1995, assuming the broadest implementation of this program.

This analysis shows that this program may result in the construction of 12,000 MW of new capacity by qualifying facilities by 1995, and the reduction in utility construction of 10,000 MW of new capacity. It also indicates a possible fuel savings in 1995 of 40,000 bbl/day of oil, 40,000 bbl/day equivalent of natural gas, and 120,000 bbl/day equivalent of coal as the use of renewable resources increases, and more efficient use is made of both renewable and non-renewable resources.

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[11] Section 102(2)(c) of the National Environmental Policy Act of 1969, Pub. L. 91-190.

The Environmental Assessment finds that there will be both adverse and beneficial environmental effects associated with this program. Some of the technologies produce certain air emissions, water effluents, and other environmental effects. However, material and thermal by-products of industrial, commercial, agricultural and other activities that would otherwise contribute to environmental degradation will be consumed or otherwise utilized in the production of useful energy under this program.

In addition, the Environmental Assessment indicates that utilities will be able to defer or cancel construction of certain facilities, originally scheduled for construction between 1980–1995. These deferrals or cancellations are expected to include some eleven 500 MW coal-fired steam plants, one 1,000 MW nuclear plant, a number of 75 MW gas turbines, and certain large scale hydropower and combined cycle installations. The environmental impacts associated with the construction and operation of these facilities would be avoided.

Finally, the market-penetration analysis in the Environmental Assessment indicates that the incentives provided by this program will not significantly affect the development of some technologies while they will significantly encourage others. For example, it appears that this program will significantly encourage small hydroelectric power development. Water power project impacts are usually site-specific and localized, with no cumulative impact on a national basis, and few impacts of regional significance. The Commission notes that hydroelectric projects in almost all cases must be licensed by the Commission. License applications are evaluated on a case-by-case basis to determine the significance of the environmental impacts and the need for a site-specific EIS. In addition, impacts of individual projects on a waterway may be cumulative, and the Commission reviews each project in relation to others on the waterway under the "comprehensive development" standard of section 10(a) of the Federal Power Act. Therefore, even though only the general nature of the kinds of environmental effects can be evaluated in this programmatic environmental assessment of national scope, requirements of the National Environmental Policy Act of 1969 (NEPA) will be met as each application is filed.

For certain other technologies, the level of environmental effects associated with the PURPA-induced market penetration of these technologies will not approach a significant level in the near term.[12] The Commission will monitor the PURPA-induced market penetration of these technologies carefully.

In the public comments, evidence was presented indicating that the environmental consequences of qualifying new diesel cogeneration may be significant in the near term, in certain geographic areas, even with a moderate level of market penetration. Therefore, the Commission believes that it is appropriate to delay action on qualification of new diesel cogeneration until completion of an EIS. The Commission will circulate a draft EIS within the next month and conclude its analysis within 90 days of circulation.

The Commission acknowledges the difficulties in identifying the levels of the environmental effects associated with the programmatic encouragement and deregulation of various types of technologies as are present under this program. There are, of course, a great number of uncertainties in any such analysis. However, the Commission is required under NEPA to assess these effects to the fullest extent possible.

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[12] See Figures 3 through 7 in the Environmental Assessment.

On the basis of its environmental review, the Commission has made the following findings in its Environmental Assessment:

—The program, taken as a whole, will not have a significant impact on the quality of the human environment within the meaning of section 102 of NEPA. The Commission also has noted certain beneficial environmental impacts that may result from this program.

—Where the expected market penetration of technologies which could qualify under this program is not expected to cause any significant environmental effects in the near term, the Commission will allow qualification of these technologies without delay.

—Where a technology is expected to cause significant environmental effects in the near term, an EIS covering the technology will be prepared and considered before the Commission acts on qualification.

—The Commission is establishing a monitoring program to alert the Commission to the likelihood or extent of market penetration by technologies which qualify under this program. This is designed to produce information that may be relevant to taking appropriate environmental protection action in the future before the program reaches a stage of investment or commitment to implementation likely to determine subsequent development or restrict later alternatives.

§ 292.204(a) Criteria for qualifying small power production facilities.

Section 292.204 sets forth qualification requirements for small power production facilities. Paragraph (a) implements the statutory requirement that the power production capacity of a small power production facility not exceed 80 megawatts at any site. In order to implement this limitation, the proposed rules provided that the capacity of all facilities which use the same energy resource, are owned by the same person, and are located within one mile of each other be added together. Commenters recommended eliminating the site criterion because the important criterion is not siting but that facilities use alternate energy resources. The Commission recognizes the difficulty in prescribing site criteria for purposes of calculation of the size of the facility. However, the Commission is obligated under the statute to limit qualifying status for small power production facilities to those facilities which have "a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts." [13]

In subparagraph (2)(i), the Commission defines "facilities located at the same site" as facilities located within one mile of the facility for which qualification is sought. Hydroelectric facilities (within this distance) are considered to be located at the same site only if the facilities use water from the same impoundment for power generation. The Commission views this additional provision for hydroelectric facilities as necessary because use of the one-mile rule alone might discourage the development of facilities on separate waterways which are within one mile of each other or of closely-spaced impoundments on an individual stream.

The Commission also notes that in some instances hydropower resources may be developed without an impoundment. In this case, the one-mile rule would be the only factor in determining the size of a facility.

In response to comments, the Commission has added subparagraph (2)(ii) which requires, for purposes of determining the distance between facilities, that any measurement shall be made from the electrical generating equipment of a facility. The comments noted that some facilities may include equipment for gathering energy to be used in the facility which may extend up to a number of miles from the generating facility. The Commission believes that the one-mile limit should be measured from the generating facilities.

The proposed rule enabled an applicant to rebut the presumption that facilities located within one mile of the facility for which qualification is sought, using the same energy resource and owned by the same person, should be considered to be located at the same site. The Commission believes that the requirement to rebut the presumption was burdensome and confusing. Therefore, the final rule has been revised to enable a small power producer or cogenerator to apply to the Commission for a waiver for good cause.

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[13] Section 3(17)(A)(i) of the Federal Power Act.

The proposed rule also contained a minimum size limit of 10 kW for qualification of small power production facilities. This proposal was based on the Commission's view that facilities smaller than 10 kW were unlikely to be economically viable, and that the administrative burden of arranging interconnected operation with them would be greater than the benefits they would provide to the system at this time. This proposal attracted considerable comment, both at the public hearings and in written recommendations. The majority of the comments objected to the minimum size provision and indicated that a number of facilities smaller than 10 kW are being built and that some units are presently commercially available. Commenters also stated that these facilities can be equipped with electrical protection equipment which permits safe interconnected operation.

Several utilities, on the other hand, suggested raising the minimum size limit, arguing that small facilities are not cost-effective. The Commission notes that the rules implementing section 210 of PURPA (Subpart C of this part) require that standard rates be provided for facilities up to 100 kW. Those rules together with the self-qualification provisions of these rules greatly ease the administrative burdens on all parties. The Commission also notes that the rules implementing section 210 of PURPA require that a qualifying facility is obligated to pay any interconnection costs assessed against it by the State regulatory authority or nonregulated electric utility. Since under these rules the utility is not obligated to incur any additional costs by reason of interconnected operation with these facilities, the minimum size limitation has been eliminated to allow individual decisions to govern whether or not to install these very small facilities.

§ 292.204(b) Fuel Use.

Paragraph (b) sets forth fuel use requirements for qualifying small power production facilities. In the proposed rule, the term "primary energy source' was not defined. Several commenters noted this fact and asked that the final rules specify a definition for the term. Subparagraph (1) provides that the primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 50 percent of the total energy input must be from these sources. The Commission notes that this requirement is not intended to force small power producers to continually monitor the energy input, but rather that reasonable estimates based on sampling methods are sufficient.

Qualifying small power production facilities using biomass as a primary energy source are treated differently than are facilities using other resources for purposes of exemption from the Public Utility Holding Company Act and certain State law and regulation under section 210(e) of PURPA and under § 292.602 of the Commission's regulations. A further concern in determining a facility's primary energy source is the treatment of mixtures of biomass and waste or renewable resources. Therefore, in subparagraph (1), the Commission specifies that any primary energy source which, on the basis of its energy content, is more than 50 percent biomass shall be considered biomass. In other words, a qualifying facility may be considered biomass-fired if, on an estimated annual basis, at least half the energy input, exclusive of fossil fuel use, is biomass.

The Commission expects that this rule will extend the benefits of the biomass exemption provisions to a broad range of facilities. For example, evidence presented in this rulemaking indicated that much more than half of the energy content in municipal solid waste is due to "organic material not derived from fossil fuels," or "biomass" under the Commission's definitions. Thus, a small power production facility fired with municipal solid waste may be considered a biomass facility. The same treatment applies to facilities fired with forest-industry residues, sewage sludge, or peat.

Another aspect of what constitutes "primary energy source" is a specification of what fuels may be used in addition to the primary energy source for purposes of ignition, startup, testing, flame stabilization and control, and during equipment outages and emergencies.

Section 3(17)(B) of the Federal Power Act, as amended by section 201 of PURPA, provides that:

> " 'Primary energy source' means the fuel or fuels used for the generation of electric energy except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy—
>
> "(i) The minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and
>
> "(ii) The minimum amounts of fuel required to alleviate or prevent—
>
> "(I) Unanticipated equipment outages, and
>
> "(II) Emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages."

The proposed rule set forth limits for the allowable use of fossil fuels. Three separate standards were proposed: One for ignition, startup and testing; another for flame stabilization and control; and a third for fuel use during outages of the primary energy supply system. All of the proposed standards were set in terms of barrels of oil per year per megawatt of rated capacity.

The comments filed on this section generally favored less restrictive fossil fuel limitations. Several commenters noted that standards written in terms of barrels of oil were imprecise, since the energy content of a barrel of oil is not constant. Other commenters argued that separate standards for startup, flame stabilization and outages were unnecessarily burdensome. Commenters claimed that some small power production technologies would be severely constrained by one of the standards, while requiring little or no fossil fuel for other purposes. Additionally, to the extent oil and natural gas remain more expensive than other energy sources available to small power producers, there is an economic disincentive to use oil and natural gas. Thus it was argued that a single standard for allowable fossil fuel use would be more equitable and workable when dealing with a number of types of facilities. The Commission has decided to adopt this recommendation.

Many other commenters recommended that the Commission adopt alternative amounts of fossil fuel for use during outages and for other purposes. For the purpose of specifying the minimum amounts of fuel under clauses (i) and (ii) of section 3(17)(B) of the Federal Power Act, the Commission adopts in this rulemaking the standard, recommended by several commenters, that no more than 25 percent of the total energy input during any calendar year may consist of fossil fuels—namely oil, natural gas, and coal.

With this simple rule, a qualifying facility can use up to the allowed quantity of fossil fuel for purposes specified in the statute. No question remains concerning what sort of primary fuel system supply outages are within the scope of the rule. The standard does require that a small power producer be able to estimate the energy content of the primary energy source. The Commission recognizes that for some energy sources, municipal solid waste in particular, energy content is not constant. As has been stated earlier, the Commission believes that reasonable estimates will suffice for purposes of this rule. Finally, it should be noted that the fossil fuel limitation applies only to small power production facilities. Some commenters apparently regarded the limitations as equally applicable to cogeneration facilities. This is not the case.

Another issue raised by the proposed rule was the limitation of renewable resources to water used at existing dams. Commenters urged the Commission to expand the definition of renewable resources to include water used at new hydroelectric facilities. The

Commission has reviewed the Conference Report and has determined that the conferees did not intend to restrict the term renewable resources to water used only at existing dams. The Commission believes that such an interpretation conflicts with the conventional use of the term "renewable resources" as including all hydroelectric sources, not just those using existing dams. Therefore, the Commission intends that the term renewable resources applies to water used at existing and new hydroelectric facilities of less than 80 megawatts.

§ *292.205 Criteria for qualifying cogeneration facilities.*

§ *292.205(a)(1) Operating standards for topping-cycle cogeneration facilities.*

In its Notice of Proposed Rulemaking, the Commission recognized the problem of distinguishing cogeneration facilities which achieve meaningful energy conservation from those which are merely "token" facilities, producing trivial amounts of either useful heat or power. In the proposed rules, the *bona fide* character of a facility was to be determined by minimum amounts of useful heat and power output.

The need for operating standards as a means of identifying *bona fide* cogeneration facilities drew considerable comment. Some comments indicated that this formulation had the effect of imposing energy efficiency requirements which are not appropriate for some technologies. Commenters stated that a much simpler test than the proposed standards would be adequate for the task. Two commenters suggested a simple test regarding the portion of energy developed in the form of useful heat or steam. One potential qualifying facility [14] suggested that:

> for geothermal energy cogeneration facilities, the energy utilization by the non-electric processes must average on an annual basis at least 5 percent of the energy consumption of the heat engine.

Another commenter suggested "a minimum of 10% of the total steam generation must be used as steam send-out." [15]

Generally, commenters did not oppose a requirement for distinguishing a *bona fide* cogeneration facility from essentially single purpose facilities, even while taking exception to the form and substance of the proposed efficiency standards. One commenter [16] stated:

> A significant portion of the steam, heat or energy available from the cogeneration unit should be used in an industrial, commercial, heating or cooling applications. The concept of an operator of a large thermal generating station applying condensing techniques taking a tiny side stream out to heat a tool shed so that cogeneration could be claimed should be prohibited.

The Department of Energy [17] recommended the inclusion of a requirement that some minimal fractions of useful heat and power be produced.

Consequently, the Commission has decided that a simple means of identifying *bona fide* cogeneration facilities is appropriate. The *bona fide* test has been modified to specify only that a minimum proportion of the useful energy output be useful thermal energy output without regard to the energy input. The standard requires that at least 5 percent of a qualifying cogeneration facility's total energy output be in the form of useful thermal energy output. Compliance with this standard is to be based on estimated annual energy output.

Further, this basic *bona fide* test is applicable only to topping-cycle facilities. "Tokenism" is of concern for bottoming-cycle facilities chiefly with regard to the opportunity for qualifying facilities to obtain exemption from incremental pricing under the Natural

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[14] Republic Geothermal, Inc.

[15] Raytheon Corporation.

[16] This commenter, Potlatch Corporation, proposed as a test that at least 25 percent of the steam, or useful energy, available be applied on an annual basis in industrial, commercial, heating or cooling uses.

[17] The Economic Regulatory Administration.

Gas Policy Act. Natural gas used by bottoming-cycle facilities (other than in supplementary firing), will, as a general matter, be exempt from incremental pricing only to the extent that reject heat is utilized in power production. In view of these provisions, no separate *bona fide* test is necessary.

§ 292.205(a)(2)(i) Efficiency standards for topping-cycle facilities.

The proposed rules set forth efficiency standards for oil- and gas-fired topping-cycle cogeneration facilities. The efficiency standards were composed of three separate criteria. The first criterion required, in effect, that no less than 20 percent of the energy input to the facility be converted to mechanical or electrical power. The second criterion specified that 45 percent of the heat rejected from the heat engine (a term used in the proposed rule to describe the power production process) be put to use in a thermal process. The final criterion required at least 60 percent of the energy input to the facility be used either as power or useful heat.

Comments on the proposed efficiency standards criticized both their form and substance. Many commenters stated that the 20 percent efficiency criterion for heat engines was overly restrictive. These commenters pointed out that most steam turbines would not be able to meet the standard with conventional steam inlet and exhaust pressures. Many such steam turbine cogeneration systems would represent energy efficient systems when compared to the standard practice of separate steam and electricity production.

Fewer comments were directed toward the efficiency tests concerning heat recovery and overall efficiency. The comments that were made, however, indicated a need for revision. One commenter indicated that the heat recovery standard would exclude diesel-powered cogeneration facilities even though many such facilities would be highly energy efficient. Comments on the overall efficiency standards were mixed. One commenter suggested that the standard was too lenient. Another commenter recommended that the proposed 60 percent test be reduced to 50 percent, although this commenter appeared to be principally concerned with the application of efficiency standards to the use of renewable resources and not to the use of scarce fuels.

Five commenters addressed the question of efficiency standards for oil- and natural gas-fired cogeneration in a comprehensive manner by proposing a complete set of alternative standards. Four of these five commenters advanced proposals based on energy balance criteria, similar in theory to the proposed standards. A proposal by the New York State Energy Office closely resembled the proposed rule. Under this plan, individual tests for heat engine efficiency, heat recovery, and overall efficiency would still be required. The overall efficiency test would remain at 60 percent, but the heat engine and heat recovery tests would be reduced to 10 percent. This was the only comment in favor of maintaining separate efficiency standards for power production and heat recovery. The criticism of that scheme has caused the Commission to adopt an alternative efficiency standard which better takes into account the variety of technologies which qualify under this rule. The essential issue concerns the proper level of the overall efficiency standard which should be applied in individual cases.

Three commenters proposed efficiency standards relating solely to overall efficiency. A utility[18] recommended a single standard of 50 percent overall efficiency, which was the most lenient standard suggested. This proposal, furthermore, would be related to design efficiency and not actual or estimated operating efficiency. Another commenter[19] recommended a single standard of 65 percent overall efficiency. This standard would be slightly stricter than the first proposal discussed for all facilities except those producing predominantly either electricity or heat. Finally, the Commonwealth of Massachusetts Office of Energy Resources proposed a standard which would weigh thermal energy with only half the value of electricity.

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[18] Brooklyn Union Gas Company.

[19] Mechanial Technology Incorporated.

The latter two comments are both supported by well-reasoned examples of cogeneration engineering practice. The Massachusetts proposal is relatively more stringent for facilities producing more heat than electricity, and more lenient for facilities producing much of their output as electricity. The basis for this proposal is a comparison of cogeneration systems based on steam turbine, combustion turbine, and diesel engine prime movers with oil-burning non-cogeneration technology. Essentially, it is argued that any cogeneration facility meeting the proposed efficiency standard will be more efficient than any combination of separately generated electricity and steam using efficient, state-of-the-art technology. By requiring that the sum of useful power output and one-half the useful thermal output be greater than 45 percent of the facility's energy consumption, this proposal would ensure that qualifying facilities produce heat and power more efficiently than a 8500 Btu/kWh combined cycle generating station and a 90 percent efficient process steam boiler.

Moreover, this proposal appears to impact the various cogeneration technologies more equitably than the other proposed standards. The other proposals for required overall efficiency, by simply summing heat and power on an equal basis, make qualification relatively easy for steam turbine systems which produce little electricity. Cogeneration systems which produce high ratios of electricity to heat would be penalized with difficult heat recovery requirements. Yet the systems with high electricity to heat ratios have the highest "second law" energy efficiencies. Futhermore, a standard which is relatively lenient towards oil- and natural gas-fired steam cogeneration would encourage boiler fuel use of distillate oil and natural gas.

The proposal of another commenter, although considered in detail, would impact different cogeneration technologies differently and would not give assurance of energy conservation.[20]

In light of the foregoing considerations, the Commission has decided to adopt a standard in paragraph (a)(2)(i) similar to that proposed by the Massachusetts Office of Energy Resources as its standard for efficiency of new oil- and natural gas-fired topping-cycle cogeneration systems. This standard requires that for any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil and the installation of which began on or after March 13, 1980,[21] the useful power output plus one-half the useful thermal energy output of the facility must be, during any calendar year, no less than 42.5 percent of the energy input of natural gas and oil to the facility. The Commission adopted a value of 42.5 percent, rather than the 45 percent recommended by the

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[20] The efficiency standard proposed by this commenter, the American Paper Institute, differed from all others fundamentally in that an effective heat rate test was required. A qualifying cogeneration facility was defined as:

A cogeneration facility that for the electric energy produced incrementally to steam or useful energy production:

1. Uses less that 9,000 BTU of additional fuel per kilowatt hour and

2. Produces more electric energy than it consumes

And that at least twenty-five percent of the steam, or useful energy, available is applied on an annual basis in industrial, commercial, heating or cooling uses.

[21] The preamble discusses new versus existing facilities. This is expressed in the regulations as "facilities, the installation of which began on or after March 13, 1980," or before that date. The Commission views the beginning of installation as the beginning of physical modification of the site or of pre-existing facilities. Of course, any sharp line will create its own inequities and raise its own questions. The waiver provision of § 292.206(d) is available to redress those inequities, and the optional procedure for qualification under § 292.207(b) is available to answer those questions.

Massachusetts comments because, in the Commission's view, the 45 percent requirement appears overly restrictive for steam turbine cogeneration facilities in that very high boiler efficiencies would have been required. However, if the useful thermal energy output of any such facility is less than 15 percent of its total energy output, the useful power output plus one-half the useful thermal energy output of the facility must be no less than 45 percent of the total energy input of natural gas and oil to the facility.

Existing Versus New Cogeneration Facilities

Although the Commission has found a compelling reason to impose efficiency standards on new oil and gas burning cogeneration facilities, the situation with respect to existing facilities is different. Existing facilities are those for which the installation of the cogeneration equipment began before the Commission actions encouraging cogeneration under this program were finalized. Presumably, such facilities would continue to be installed or operated using whatever fuels they are equipped to burn, with or without the incentives of PURPA.

Allowing existing facilities to qualify will provide for more flexible operation of the facilities. Optimum efficiency of a cogeneration facility may be more easily approached through interconnected operation with an electric utility. Because of the foregoing considerations, denial of qualifying status would serve no useful purpose.

Existing cogeneration facilities burning oil or natural gas were, in large measure, installed in an environment of lower fuel prices. Such facilities may not be able to meet the higher standards now reasonable for use of scarce fuels. Yet failure to meet standards intended for new facilities should not preclude entitlement to sell power to the utility and to receive the other rate benefits, as provided under Subpart C of these rules. In addition, the denial of exemption from regulation as an electric utility may discourage cogeneration at existing facilities.

The Commission has decided against imposing any efficiency standards on existing facilities, regardless of energy source. There is no assurance that imposing standards would result in fuel savings. The opposite result is more likely, if operating cogeneration facilities are denied the benefits of interconnected operation with an electric utility. Therefore, for any cogeneration facility, the installation of which began before the date the Commission's final rules in this docket were issued, March 13, 1980, no efficiency standards are required for qualification, regardless of energy source or whether it is a topping or bottoming-cycle facility.

Efficiency To Be Based Upon Projected Annual Operation

Several commenters raised the issue of whether efficiency calculations should be based on rated performance characteristics or on expected performance over a period of time. Only half of the commenters that mentioned the issue took a position in favor of one means of computation or another. The balance of the commenters merely asked for clarification.

The Commission is persuaded that the efficiency of a cogeneration facility operating at peak production of power and heat may not necessarily correlate with the efficiency which can be practically realized. A cogeneration facility which serves a highly variable heating load may seldom be operated at peak efficiency. The efficiency standards required for new oil or natural gas cogeneration facilities are intended to assure efficient use of these premium fuels. Use of optimum or design basis circumstances for determining efficiency would not satisfy the Commission's concern. A computation based upon projected or estimated annual operations will more closely reflect the facility's actual energy conservation potential.

The Commission realizes that estimates will be required in order to determine the efficiency of a facility not yet constructed. The Commission believes, however, that such estimates would routinely be performed prior to any decision to invest in cogeneration equipment. No significant burden is therefore expected in determining a cogeneration facility's qualifying status.

Why the Efficiency Standard Based on "Effective Heat Rates" Was Not Adopted

Evaluating the performance of a cogeneration facility in terms of the quantity of additional fuel used per kilowatt hour of electricity generated, above that needed for heating purposes alone, results in a standard known as the "effective heat rate".[22] This form of efficiency evaluation has been widely used to compare cogeneration of electricity to conventional utility generation. For a typical backpressure steam turbine cogeneration facility the effective heat rate of electricity generation may be as low as 4500 BTU/kWh—twice the efficiency of central station utility generation.

The effective heat rate test has some serious drawbacks, however. The test looks only to the efficiency of electricity generation and ignores the balance of the cogeneration facility. While the effective heat rate of a topping turbine may be high, if only a small fraction of the energy produced is in the form of electricity, the overall system is essentially a boiler facility, and the aggregate energy conserved is minimal. Indeed, effective heat rates are most favorable for systems which produce little electricity and a large amount of steam. The effective heat rate is lower for combustion turbine and internal combustion cogeneration, as compared to steam, but such systems produce more electricity per unit of fuel used. When the efficiency of the entire system is computed in such a manner as to credit the quality as well as quantity of energy produced,[23] combustion turbine or internal combustion cogeneration systems consistently score higher than steam systems. Thus the effective heat rate test does not truly measure overall system efficiency, and is not an adequate measure of whether, in the aggregate, energy is conserved through cogeneration.

§ 292.205(a)(2)(ii) Topping-cycle facilities using energy sources other than oil or natural gas.

In the final rule, the Commission has decided not to impose efficiency standards for qualification of topping-cycle cogeneration facilities using energy sources other than oil or natural gas. The proposed rules contained standards for topping-cycle cogeneration facilities using energy sources other than coal or coal-derived fuels. The efficiency standards were proposed in response to two concerns. First, some energy sources may be viewed as limited in access. Use of such resources by one cogenerator deprives another, possibly more efficient cogeneration facility, of the opportunity to use the resource. Efficiency standards were proposed in order to ensure that the first cogenerator, to gain access to the resource, would build an efficient facility in the absence of an effective market for the resource.

The second concern dealt with a means of distinguishing a *bona fide* cogeneration facility from a small power production facility with incidental recovery and use of steam or heat. The Commission believed that some means was necessary to prevent small power production facilities from evading the statutory size limits. A standard setting forth minimum production of power and minimum recovery of heat was seen as a means of avoiding the qualification of "token" cogeneration facilities.

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[22] To compute a cogeneration facility's effective heat rate, an assumption is made that the thermal output of the facility would have to be supplied in any event. A certain quantity of fuel would be needed to satisfy the thermal load in the absence of cogeneration. For example, if a steam turbine topping-cycle cogeneration facility were not installed, a conventional steam boiler would raise the steam. With the topping-cycle system, slightly more fuel is burned to raise steam at a higher pressure than is needed for the thermal process. The steam is expanded in a turbine, generating electricity and exhausting steam at the proper pressure for the thermal process. Effective heat rate is computed by dividing the extra energy supplied to the facility by the electricity generated.

[23] A Btu of electricity, for example, is worth more than a Btu of low pressure steam. The steam may be used for heat, but it is not useful for lighting or operating a television set. The "Second Law Efficiency" concept accurately reflects the usefulness of various forms of energy.

Neither concern is, however, relevant to the use of coal as a primary fuel. Coal is not characterized by limited access and it cannot be used as a primary fuel by small power production facilities. Therefore, the proposed rule contained no efficiency standards for facilities fueled by coal.

Most commenters addressing this question stated that the proposed standards were impossible to meet in many instances. More importantly, commenters questioned the basic rationale of applying efficiency standards. The limited access concept is complex, and some commenters missed the point, arguing that such resources are renewable or available in large quantity.

EPA pointed out that the degree to which limited access may affect the sort of facility constructed is unknown. The effects of limited access, if any, are likely to be site specific, and will vary with time. Even if these effects could be spelled out with certainty, the specification of appropriate efficiency criteria would be a difficult task at best. If a standard of thermal efficiency were set without detailed knowledge of both the technologies and patterns of resource development, the probable effect would simply be to stifle development of the resource.

The Commission concludes that the proposed cure is far worse than the suspected ailment. In addition, as was stated in the discussion addressing the operating standards, the 5 percent minimum amount of useful thermal output standard will assure that these facilities are *bona fide* cogenerators under these rules.

§ *292.205(b) Efficiency standards for bottoming-cycle facilities.*

The proposed rule contained a two-part efficiency standard for bottoming-cycle cogeneration facilities. All facilities, except those using coal or coal-derived fuels, would have been required to meet the standards. The first part of the efficiency standard dealt with the heat engine. In order to qualify, a facility had to either convert 15 percent of the reject heat from the thermal process to mechanical energy, or in the alternative, achieve 40 percent of the ideal Carnot efficiency with the working fluid temperatures experienced. The second part of the standard simply required an overall energy efficiency of 60 percent for the entire facility.

Numerous commenters were critical of the proposed standards. Although a number of issues were addressed, a common concern was the counter-productive nature of efficiency standards for bottoming-cycle cogeneration facilities relying on reject heat. It was argued that because the heat would otherwise be wasted, efficiency standards would serve no fuel conservation purpose. The only effect of efficiency standards would be a limitation on the number of bottoming-cycle facilities which would be constructed.

Moreover, many commenters noted that the overall energy efficiency standard of 60 percent was overly restrictive, and in fact meaningless in many instances. The overall energy efficiency, as defined in the proposed rule, would be determined by the efficiency of the bottoming-cycle heat engine and the efficiency of the industrial thermal process. Typically the latter efficiency is predetermined by the nature of the process and the design of the industrial plant. When bottoming-cycle cogeneration equipment is added to an existing plant, the efficiency of that plant's energy utilization is irrelevant to the effectiveness of the bottoming cycle. Furthermore, the measurement of overall energy efficiency required under the proposed rules would be difficult, since such efficiency measurements are not a conventional practice.

The Commission recognizes the validity of these comments, and has therefore eliminated efficiency standards for most bottoming-cycle cogeneration facilities. The final rule contains an efficiency standard for only those facilities with oil or natural gas supplementary firing. The need for standards in this case was acknowledged by several commenters.

When supplementary firing is used in a bottoming-cycle cogeneration facility, more than reject heat is used to generate electricity. Scarce fossil fuels can be introduced without the inherent efficiency advantages of sequential use. In order to restrict the potential for abuse, the Commission has adopted a simple efficiency test similar to that suggested by one of the commenters. The standard relates only to facilities installation [24] of which began on or after March 13, 1980, and for which any of the energy input as supplementary firing is oil or natural gas. Paragraph (b)(1) specifies that the useful power output of the bottoming cycle must, during any calendar year, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing. The Commission notes that the fuels used in the thermal process "upstream" from the bottoming-cycle facility's power production system are not considered in this efficiency test. The use of the lower heating value, consistent with the proposed rules, is advantageous to cogenerators in that the latent heat of combustion water cannot be effectively recovered by any practical bottoming-cycle technology currently foreseeable.

§ *292.205(c) Exemption from incremental pricing.*

One of the incentives for cogeneration is found not in PURPA but in the Natural Gas Policy Act of 1978 (NGPA). In section 206(c), the Commission is given the discretion to exempt qualifying cogeneration facilities from its incremental pricing program developed under Title II of the NGPA.

On September 28, 1979, the Commission issued final rules implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978.[25] These rules provide, among other things, that natural gas used by "a qualifying cogeneration facility" shall be exempt from the incremental pricing provisions of the NGPA.[26] A qualifying cogeneration facility is defined in the regulations as a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[27]

In this paragraph, the Commission has set forth the requirements for exemption from incremental pricing. Paragraph (c)(1) allows that any topping-cycle cogeneration facility which is a qualifying facility under § 292.203(b), and, if not already required to do so, meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section, or is a qualifying facility under Subpart E of this part, may obtain an exemption from incremental pricing for its natural gas use.

Paragraph (c)(2) enables natural gas used in bottoming-cycle cogeneration facilities and which is not exempt from incremental pricing under Subpart E of this part to obtain exemption under this subpart to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production. The Commission feels that these requirements adequately reflect the goal of PURPA to encourage the efficient use of energy by cogeneration facilities. To the extent that a facility makes available its reject thermal energy to produce power, the Commission believes it should obtain the benefit of exemption from incremental pricing.

The Commission does not intend for this subpart to interfere with any exemptions provided under Subpart E. Therefore, paragraph (c)(3) provides that any person who obtained an exemption under Subpart E is not affected by this provision.

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[24] In the case of bottoming-cycle cogeneration in which electric generating equipment is retrofitted to existing sources of industrial reject heat, the date at which installation begins is the date on which the retrofit is begun.

[25] 18 CFR Part 282, 44 FR 57226 (Oct. 5, 1979).

[26] 18 CFR 282.201(a).

[27] 18 CFR 282.202(e).

Paragraph (c)(4) provides that natural gas used for supplementary firing in any cogeneration facility is not eligible for exemption from incremental pricing under this subpart. However, natural gas used for supplementary firing of a bottoming-cycle facility would be exempted under the Commission's Order No. 49–A, to the extent that the facility generates electricity which is sold to a utility.[28]

When the final regulations under Phase II of incremental pricing take effect and the Commission can then better assess their implications, the Commission may wish to revise the exemptions from incremental pricing to cogeneration facilities, including the exemption provided in the Interim Rule under Subpart E.

§ *292.205(d) Waiver.*

This paragraph provides that the Commission will consider waiving any of the standards described above upon a showing that the facility will produce significant energy savings.

§ *292.206 Ownership criteria.*

Section 292.206 is designed to implement the statutory requirement that a qualifying small power production facility or cogeneration facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). Regarding this provision, the Commission notes that the Conference Report states that:

> [e]lectric utilities may participate in an entity which owns such (qualifying small power production or cogeneration) facilities with other persons, and such entity could qualify under these definitions.
>
> The test of this case is whether the entity which owns the facility is primarily engaged in the generation or sale of electric power other than in connection with its ownership of the cogeneration facilities or small power production facilities.[29]

Thus, either directly or through a subsidiary company, an electric utility could participate in the ownership of a qualifying cogeneration or small power production facility.

Several commenters noted that under a literal interpretation of the Conference Report's statement, several electric utilities could form a subsidiary which owned small power production or cogeneration facilities. Such a subsidiary would constitute an entity which is not primarily engaged in the generation or sale of electric power other than in connection with its ownership of cogeneration or small power production facilities. Under such an interpretation, the subject facilities would be eligible to receive qualifying status.

The Commission believes, however, that the thrust of section 201 of PURPA is to limit the advantages of qualifying status to cogeneration and small power production facilities which are not owned primarily by electric utilities or their subsidiaries. The proposed rule provided that if, based on the proportion of ownership by electric utilities, public utility holding companies, or subsidiaries of either, more than 50 percent of the entity which owns the cogeneration or small power production facility is comprised of these electric utility interests, then the facilities are not qualifying facilities. This language has been incorporated into these final rules; the comments on this section provided no sufficient reasons in the Commission's judgment for changing the percentage.

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[28] See Order No. 49–A, issued December 27, 1979, in Docket No. RM79–14, 45 FR 21 (Jan. 2, 1980).

[29] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 89, 95th Cong., 2d Sess. (1978).

The Commission emphasizes the fact that nothing in this program limits the extent of utility ownership or operation of cogeneration or small power production facilities. The Commission notes the statement in the Conference Report that:

> . . . it is also the intention of the conferees that the definition of "qualifying cogeneration facility" and "qualifying small power production facility" will not be construed as prohibiting or discouraging electric utilities from cogenerating.[30]

Utilities may not, however, qualify for the benefits under this program if their ownership interests exceed the limits set forth in this rule.

Both the provisions in section 3(17)(C)(ii) and 3(18)(B)(ii) of the Federal Power Act, as amended by section 201 of PURPA, use the term person in describing who may own a qualifying cogeneration facility and qualifying small power production facility. The Commission has incorporated the ownership criteria under this section of the regulations and has used the term—person—found in the statute.

A few commenters questioned whether a municipality (or any other agency or instrumentality of State or Federal government) falls within the definition of the term "person" as used in definitions (17) and (18) in section 3 of the Federal Power Act. It is the Commission's view that the term "person," for purposes of qualifying under this program, does include municipalities (or any other agency or instrumentality of State or Federal government). This view is supported by case law in which the courts have treated municipalities and other units of State and Federal government as persons under other sections of the Federal Power Act. *See, e.g., United States v. Public Utilities Commission of California*, 345 U.S. 295 (1953); and *New England Power Co. v. FPC*, 349 F.2d 258 (1st Cir. 1965). The cases touching on the issue of these agencies as persons are very expansive (see the *California Public Utility Commission* decision cited above which was decided by the Supreme Court in 1953). Therefore, under past practice, the Commission and the courts have not interpreted "person" to exclude a municipality or other unit of State and Federal government from the benefits of any action of the Federal Power Act.

In addition, in that there is no indication that the Congress meant to deny qualification to these agencies or instrumentalities, the Commission finds no policy grounds for denying these agencies or instrumentalities qualifying status. Therefore, both as a matter of law and as a matter of policy, the term "person" as used in section 3(17)(C)(ii) and 3(18)(B)(ii) includes these agencies or instrumentalities. The effect of this is to allow these agencies or instrumentalities the opportunity to participate in this program if they otherwise meet the standards for qualification set out in this subpart.

§ 292.207 Procedures for obtaining qualifying status.

This section sets forth the procedures for obtaining qualifying status. Paragraph (a)(1) provides that a small power production facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility. As discussed above, the Commission has eliminated the mandatory case-by-case qualification procedure contained in the proposed rule.

Paragraph (a)(2) requires any owner or operator of a facility qualifying under paragraph (a)(1) to furnish notice to the Commission. The contents of the notice shall contain the information required of an applicant for qualifying status in paragraph (b)(2)(i) through (b)(2)(iv) described below. The Commission is requiring such notice for purposes of monitoring the market penetration of qualifying facilities, in compliance with its responsibilities under the National

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[30] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 89–90, 95th Cong., 2d Sess. (1978).

Environmental Policy Act of 1969, as previously discussed in this preamble.

Paragraph (b) provides an optional procedure whereby the owner or operator of a small power production facility may, should it prove desirable, file an application with this Commission for certification that the facility or cogeneration facility is a qualifying facility. The application must contain enough information to enable the Commission to make an accurate finding that the facility should or should not be certified.

Specifically, paragraph (b)(i) through (v) provides that each application must contain the name and address of the applicant and the location of the facility, a brief description of the facility including a statement indicating whether such facility is a small power production facility or a cogeneration facility, the primary energy source used or to be used by the facility, the rated power production capacity of the facility, and the percentage of ownership by electric utilities, or public utility holding companies, or by any person owned by either.

Applications by owners or operators of small power production facilities must also contain the location of the facility in relation to any other small power production facilities within one mile of the facility owned by the applicant which use the same energy resources, and information identifying any planned usage of natural gas, oil or coal.

An application by a cogenerator must contain the date installation facility commenced, a description of the cogeneration of the facility, including whether the facility is a topping or bottoming cycle, and sufficient information to determine that any applicable efficiency or operating requirements have been met.

Paragraph (b)(5) sets forth the procedures to be used by the Commission to determine whether a facility is to be granted qualifying status. It provides that, within 90 days of the filing of a complete application, the Commission shall issue an order granting or denying the application, extending the time for issuance of an order, or setting the matter for hearing. If no order is issued within 90 days of the filing of the application, it shall be deemed to have been granted.

The Commission will rely on its existing procedures for any person to file a petition for reconsideration of any Commission action instead of employing the protest procedure contained in the proposed rule.

Several commenters, while offering support for the elimination of filing and notice requirements for smaller facilities, acknowledged the useful purpose that would be served by a requirement that a larger facility give notice to the affected utility of its qualifying status and its intention that such utility purchase its power. Accordingly, the Commission has provided a requirement in paragraph (c) that an electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kilowatts or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b).

Paragraph (d)(1) provides that the Commission may revoke the qualifying status of a facility if it ceases to comply with any of the statements contained in its application for Commission certification. The Commission may do so on its own motion, or upon a motion to reconsider any certification previously granted. In either case, the Commission will act only after providing an opportunity for a hearing. Paragraph (d)(2) provides that, prior to undertaking any substantial alteration of a qualifying facility, a small power producer or cogenerator may, should it prove desirable, apply to the Commission for a determination that the facility, as modified, will retain its qualifying status.

IV. Effective Date

The Conference Report indicates that rules respecting criteria for qualifying facilities be prescribed "as soon as practicable" in order that persons may ascertain in advance of construction or operation of any facility whether or not such facility will meet the criteria established. The Commission believes, therefore, that good cause exists under 5 U.S.C. 553(d) to make the rules promulgated in this order effective immediately.

These rules have been promulgated under the Federal Power Act, as amended by PURPA, and, therefore, a right to rehearing exists under section 313 of the Federal Power Act.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, (15 U.S.C. 791 *et seq.*), Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, (42 U.S.C. 7101 *et seq.*), E.O. 12009, 42 FR 46267, Natural Gas Policy Act of 1978, (15 U.S.C. 3301, *et seq.*))

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective immediately.

By the Commission.

Kenneth F. Plumb,

Secretary.

Appendix I

Note.—This Appendix should not be included in the text of the regulations in the Code of Federal Regulations.

Summary of Comments on Preliminary Environmental Assessment

General. Numerous comments addressed the Environmental Assessment in general and discuss the need for a programmatic environmental impact statement (EIS).

Some of the comments favored an environmental impact statement. The New England Chapter of the Sierra Club stated that it is in accord with the general thrust of the Environmental Assessment. However, it is concerned with the encouragement of those technologies which utilize non-renewable energy resources and with those technologies which, if uncontrolled, tend to produce large quantities of pollutants. Therefore, the commenter stated that a generic EIS is needed to examine the absolute environmental effects of the rulemaking in encouraging all the assumed "benign" technologies.

This commenter also concurred with the suggestion that, pending issuance of a generic environmental impact statement, the Commission should proceed with the implementation of rules and regulations under sections 201 and 210 of PURPA, except for technologies which may result in significant impacts as a result of the rules. For these technologies, the comments recommended that the Commission should proceed promptly to produce a comprehensive generic environmental impact statement.

Southern Company Services suggested that while the requirement to file an environmental impact statement may temporarily discourage cogeneration or small power production, it appears to be the only procedure for determining the environmental acceptability of a qualifying facility.

The Solar Lobby endorsed preparation of an EIS only where the environmental consequences of a qualifying facility are clearly negative. This commenter recommended that the more benign technologies should be encouraged even while appropriate generic environmental impact studies are performed.

Arthur D. Nadler Associates added that the environmental impact statement requirements should be kept to a minimum and be consistent with the small size of the facilities generally associated with these technologies.

Other commenters are opposed to the idea of a generic EIS. The California Energy Commission argued that the Commission's Environmental Assessment is adequate and that an EIS should not be required, particularly since any individual qualifying facility will receive State and Federal environmental scrutiny before it is constructed.

The California Energy Commission also suggested that the delay in adopting these regulations while an EIS is prepared and issued would itself cause adverse environmental and socioeconomic effects. Arizona Public Service Company and Brooklyn Union Gas Company concurred with the thrust of California's comment that, "Qualifying facilities will be delayed or not developed if the regulations are not adopted immediately. The failure to develop these qualifying facilities in a timely fashion will result in increased air pollution and adverse socioeconomic impacts from the increased consumption of imported oil and other fossil fuels during the period until the regulations are issued."

The Missouri Public Service Commission stated that for residential cogenerators or small power production facilities, an environmental impact statement will work as a disincentive, hindering consumer efforts at alleviating the energy problem. This commenter noted that while section 201 and 210 rules do have an effect on the quality of the human environment, it is a very beneficial one in that this program offers some viable alternatives for easing the energy problem. "As little interference by government with its agencies should be the goal so that American ingenuity and know-how can flourish."

Pan Tech Management stated that the PURPA rules will not constitute an action that will significantly affect the environment. This commenter recommended that the Commission promulgate the proposed rule with appropriate modifications based on public comment, but that it should not withhold promulgation of any part of the rules pending preparation of an EIS. The Commission should, in this commenter's view, review case-by-case, certain locations where environmental quality may already be below the standard (i.e. non-attainment areas with regard to air quality criteria), thus precluding the implementation of certain technologies.

The Colorado Office of Energy Conservation suggested that a much more critical need than an EIS for small power producers is a social and economic impact analysis.

Cogeneration technologies and their environmental impacts.

With regard to cogeneration, the commenters generally suggested that diesel cogeneration in congested urban areas may have adverse air quality effects.

Consolidated Edison, Boston Edison and Union Electric and separate comments by Southern Company Services stated that the proliferation of relatively small diesel cogeneration units installed in residential and commercial buildings would significantly affect the environment. The joint comments noted that each individual unit would likely escape any meaningful environmental review by State and Federal environmental authorities under current regulations, and yet the cumulative impact could well be serious. It was asserted that the problem will be particularly acute in areas where the attainment of national ambient air standards already is marginal (most congested urban areas), and where increases in pollutant concentrations would restrict opportunity for urban development and economic recovery. It was further asserted that most of the cogeneration is likely to be diesel engines, which these commenters stated emit larger amounts of some critical pollutants, per unit of energy produced, than do properly designed central power station plants. The joint comments stressed that cogeneration facilities discharge pollutants in non-buoyant plumes at roof-top levels which it was claimed will cause far greater pollution concentrations at street levels where people live and breathe, than do the buoyant plumes from the high, free-standing stacks of powerplants.

One of the commenters, Consolidated Edison, stated that on-site electric generation using diesel engines with waste heat recovery systems is already an economic alternative to its electric service or, in some cases, a combination of its electric and steam services, for some 395 customers representing a combined peak load of more than 1,000 MW. As additional incentives are added to the already favorable tax and regulatory climate for cogeneration installations in its service area, the utility claimed that the potential for conversions from central station to on-site generation could increase.

Consolidated Edison cited several studies prepared at its request which indicated that nitrogen dioxide (NO_2) standards in Manhattan could be contravened with the addition of as little as 240 MW of diesel cogeneration facilities in that borough. Consolidated Edison also stated that the studies indicated that the primary annual air quality standard for sulfur dioxide (SO_2) will be exceeded after several hundred more megawatts of diesel cogeneration capacity are installed.

Thomas Casten, speaking on behalf of The Cogeneration Society of New York, criticized several assumptions used in the Consolidated Edison studies. First he stated that several of the cogeneration facilities which the studies assumed would be installed in New York City violate existing environmental laws, and, therefore would not be installed. Secondly, he stated that these studies assume that 75 percent of the cogeneration plants would be installed in Manhattan, where environmental impacts would be most severe. He noted that eighteen of nineteen existing cogeneration plants in New York city are located outside of Manhattan.

This commenter next criticized the assumption that more than one thousand megawatts of diesel cogeneration will be installed in the New York City area, on the basis that this figure seems to exaggerate greatly the likely amount of cogeneration capacity. In addition, he contended that the standards used for measuring the emissions were those used for truck and bus-type engines which operate at varying speeds. He stated that a typical diesel cogeneration facility would operate at a fairly constant speed; and that, at constant speeds, emissions are about one-fourth of those produced at varying speeds.

Finally, the commenter noted that these studies assumed that there would be no improvements in the environment resulting from other factors during the time that the one thousand megawatts of diesel cogeneration were projected to be installed in New York City.

Commonwealth Edison and Consolidated Edison suggested that noise produced by diesel engines is a very serious environmental impact, and that the impact in any specific area is independent of the total number of units in any region. These commenters recommended that an environmental noise impact assessment be prepared and the appropriate noise abatement measures be included in the on-site diesel-engine installations. This could be done, they asserted, by requiring potential cogeneration facilities to prepare a noise emission analysis showing that the emissions would not contravene local or State requirements.

Consolidated Edison, Boston Edison, Union Electric and Southern Company Services, Inc. recommended that in light of the serious environmental consequences which are likely to flow from these rules, it is incumbent upon the Commission to accompany its proposed rules with a draft environmental impact statement.

Furthermore, Consolidated Edison, Boston Edison, and Union Electric suggested that an environmental impact statement should be required with respect to each new cogeneration facility having the potential for a significant adverse impact on the environment. The comments stated that any proposed facility having a generating capacity of 500 kW or more would have such an impact and should require an EIS.

Brooklyn Union Gas Company surveyed eight companies with cogeneration facilities and concluded that no environmental problems have been associated with the operation of the facilities. The facilities obtained the required air emissions permits and have been operating in compliance with applicable air quality regulations.

Penti Aalto, a consultant, suggested that all types of cogeneration facilities be permitted without an EIS, subject to periodic review of the system as a whole. If problem areas appear, then appropriate action could be taken.

The New York State Public Service Commission proposed limiting qualifying status to suitable locations or limiting the density of qualifying facilities in any given area.

The New York State Energy Office stated that an EIS is not necessary at this time. It proposed as an alternative that the Commission consider imposing a direct limitation upon the density of diesel cogeneration in large populated urban areas since the preliminary EA concludes that the number and density of urban diesel cogenerators determines the environmental risk.

Small Power Production Facilities.

Solar Energy. The Colorado Solar Energy Association stated that nearly all solar electric options are far less damaging to the environment than fossil-fueled or nuclear electric generation. He noted that implementation of PURPA must not be delayed by requiring the preparation of lengthy and time consuming environmental impact statements for renewable energy based qualifying facilities.

Geothermal Energy. The New England Chapter of the Sierra Club suggested that geothermal power production using hot brine sources is acknowledged to pose problems of air and water pollution and a potential toxic waste disposal problem. This commenter recommended that since there are no immediate plans for small power plant construction using hot geothermal brine (it is their understanding that such power production is currently uneconomic), it seems unnecessary to promulgate rules to encourage its use prior to preparation of the generic EIS.

Small-Scale Hydropower. The State of Vermont—Agency of Environmental Conservation stated that the small hydro summary in the preliminary EA was incorrect in stating that instances are rare where there is significant impact from facilities being added to an existing dam. It was stated that as in the Bolton Falls project, or at Ball Mountain, the impact of development could be significant in terms of water quality, fishery habitat and production, recreation, and possibly aesthetics.

The New England Chapter of the Sierra Club suggested that run-of-river hydro installations suffer from the same siltation, turbidity, and biological oxygen demand problems as do generating capacity additions at existing dams. Because almost all new non-Federal hydroelectric projects must be licensed by the Commission and environmentally evaluated on a case-by-case basis, this commenter concurred with the promulgation of rules allowing qualification of small hydroelectric projects at existing dams. It was asserted that run-of-river hydroelectric projects, however, pose an additional problem: the potential for diversion of water from existing channels. Unless all run-of-river hydro projects are to be environmentally evaluated on case-by-case basis, this commenter recommended that qualifying status be withheld until after completion of the generic EIS.

Municipal Waste. Wheelabrator-Frye, Inc. stated that the encouragement of small power production and cogeneration fueled by municipal solid waste does not constitute a "major federal action significantly affecting the quality of the human environment." This commenter stated that small power production facilities which use such a feedstock produce a significant net *positive* impact on the overall environment since they reduce dependence upon highly polluting "open dumping" practices and encourage more efficient community solid waste management practices. He cited as an example one of the projects sponsored by his firm which has achieved waste volume reduction of more than 90 percent through currently available mass combustion technologies. He suggested that the quantity of waste requiring land disposal sites, as a result of processing through such facilities, is greatly reduced and more readily controlled and contained.

This commenter also suggested that since current EPA standards governing State implementation plans and new source performance procedures assure the conformance of such projects with the attainment of national air quality standards, no environmental impact statement need be filed by these facilities.

However, the New England Chapter of the Sierra Club stated that incineration of municipal wastes for power production purposes presents a potential problem in the emission of toxic substances, especially the more volatile heavy metals like mercury, cadmium and lead. With the eventual issuance of EPA regulations implementing the Toxic Substances Control Act, these emissions will be regulated; at this time they are not. This commenter does not propose an exception for municipal waste, but is concerned that any Commission regulations which encourage the incineration of municipal waste should insist on appropriate control technology.

Biomass. The New York State Energy Office and the Hawaiian Sugar Planter's Association stated that a detailed Environmental Assessment is not warranted for any of the biomass fuels already in use at small power production facilities.

The Hawaiian Sugar Planter's Association suggested that, in large part, the PURPA incentives should operate to encourage sugar factories to make more efficient use of the biomass already being burned and more efficient use of the steam being produced.

The New England Chapter of the Sierra Club stated that emission, soil tilth, fertility, and land use questions are present for biomass fuel. This commenter is concerned with the social effects of industrialization of agricultural areas induced by new biomass cogeneration facilities. "Biomass generally will provide relatively small amounts of net energy per unit mass or volume. As a result, encouragement of new biomass cogeneration facilities will tend to increase rural industrialization because high transportation costs will attract industrial cogenerators to the source of the biomass."

This commenter stated that it is not necessary to require an environmental impact statement for existing facilities or biomass cogeneration which use on-site produced waste—such as sawdust. However, it was suggested that an impact statement for new biomass-based cogeneration facilities which import off-site produced forest or agricultural products for the purpose of cogeneration should be required. "Cogeneration based on the use of stockyard wastes, kelp or similar sources need not be excepted if a thorough generic EIS is planned."

The Solar Energy Research Institute suggested that it is a mistake to group all types of "biomass" generating facilities together for environmental scrutiny. Many biomass systems use biogas in a combustion turbine and have minimal environmental impacts. This commenter recommended that several different classes of "biomass" facilities be identified and that each be considered separately.

The American Paper Institute stated that it was concerned that the Commission staff may not have taken into account many of the environmental benefits of burning wood and other biomass fuels.

Potlatch Corporation suggested that the definition of biomass in the preliminary environmental assessment is unusual and narrow. "Well-recognized concepts of biomass include all plant material including by-products of manufacturing, harvesting, and growing."

Wind. Two commenters suggested that the environmental effects of large wind energy conversion systems (WECS) can be significant. The State of Vermont—Agency of Environmental Conservation raised several problem areas. The first is that electromagnetic interference (as with radio or telecommunications) is an unknown quantity at the moment, with disagreement as to the extent of

disruption that will actually be caused by a large WECS.

The second problem discussed was road construction and site preparation, especially on the fragile areas such as sites above 2500 feet in elevation. The wind energy resource appears to exist predominately at these higher elevations, yet sites which may be desirable from a power point of view are fragile and easily disrupted. Loss of vegetation cover and erosion of soil are two of the main concerns.

A third problem raised by this commenter was that the noise pollution and visual impact of the WECS were not mentioned in the summary of the preliminary Environmental Assessment.

The Solar Energy Research Institute recommended that the environmental impacts of large wind machines may need more careful scrutiny than the preliminary EA acknowledged. It was asserted that difficulties with low frequency sound and land use impacts need careful attention.

[¶ 30,135]

45 F. R. 18915 (March 24, 1980)

18 CFR Part 271

[Docket No. RM80-44; Order No. 72]

Final Regulations Implementing Section 109 of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) hereby reissues as final regulations its interim regulations implementing section 109 of the Natural Gas Policy Act of 1978 (NGPA). The primary purpose of the final rule is to resolve the central question of interpretation of section 109 by determining the proper scope of applicability of that section. In the final rule, the Commission reaffirms the interpretation of section 109 embodied in the interim regulations that section 109 applies only to first sales of natural gas not subject to a maximum lawful price under any other section of Title I of the NGPA.

EFFECTIVE DATE: March 18, 1980.

FOR FURTHER INFORMATION CONTACT:

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Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

Issued: March 18, 1980.

I. Background

On December 1, 1978, the Commission issued interim regulations[1] implementing the Natural Gas Policy Act of 1978 (NGPA).[2] Under the interim regulations, the maximum lawful price established under section 109(b) is applicable to first sales of natural gas not subject to a maximum lawful price under sections 102, 103, 104, 105, 106, 107 or 108 of the NGPA.[3]

The interim regulation, which defines the scope of applicability of section 109, was based on the Commission's interpretation of the following language of section 109(a):

> **Sec. 109. Ceiling Price for Other Categories of Natural Gas.**
>
> **(a) Application—The maximum lawful price computed under subsection (b) shall apply to any first sale of any natural gas delivered during any month, in the case of any natural gas which is not covered by any**

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[1] 43 FR 56448 (Dec. 1, 1978).

[2] 15 U.S.C. 3301 *et seq.*

[3] 18 CFR 271.901

QUESTIONS FROM SENATOR MCCLURE

PURPA

Question 2: Is there anything in PURPA, or the regulations implementing PURPA, which require a state public utility commission to require electric utilities to purchase power from QFs if there is no need for the power?

Answer: Neither PURPA nor the FERC implementing regulations require a state public utility commission to require electric utilities to purchase excessive power from QFs (i.e., either electric energy or capacity or both). Section 210 of PURPA requires the FERC to implement rules which "require electric utilities to offer to purchase...electric energy from such [QF] facilites." In implementing these regulations the FERC recognized the need to establish rates based on the utility's avoided costs. Based on this recognition, **C.F.R. 292.304(f), Periods during which purchases not required,** states:

> "(1) Any electric utility which gives notice...will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself."

The C.F.R. further provides that any utility claims exercised under this section are subject to review and verification by the State regulatory authority.

Prepared by: Robert L. San Martin
Date: 7/11/90
Coordinated with:
Reviewed by: J. Michael Davis, P.E.
Assistant Secretary
Conservation and Renewable Energy

QUESTIONS FROM SENATOR MCCLURE

PURPA

Question 3a: Is there anything in PURPA, or the regulations implementing PURPA, which require a state public utility commission to require electric utilities to pay excessive amounts for the QF power they do purchase?

Answer: No. According to both the statute and the implementing regulations, individual state public utility commissions are required to set the price for "purchases from QFs, absent negotiations, at the statutory ceiling." While this does serve to maximize the incentive for utilities and QFs to negotiate a transaction, the avoided cost can neither be greater than nor less than "the price the utility would have paid for comparable power from other sources, including other wholesale sources." (FERC Docket No. RM88-6-000, source for each of the above quoted references).

PURPA's statutory provisions and subsequent governing regulations provide a broad framework for individual State regulatory bodies to function within; however, this federally implemented framework has allowed for a wide range of interpretation at the State level. As a result, a number of participants on each side of the PURPA equation (i.e., QFs and utilities) have taken exception with State administrative determinations of avoided cost.

These problems are gradually being eliminated because States and utilities are moving toward competitive bidding and allowing market mechanisms to determine a utility's true avoided cost. This should ensure that excessive amounts are not being paid.

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QUESTIONS FROM SENATOR MCCLURE

PURPA

Question 3b: Have state Commissions adjusted their implementation of avoided cost to match changed circumstances?

Answer: Yes. Changing circumstances within the electric power sector have influenced the evolution of state implementation of avoided costs. These adjustments range from revised avoided cost benchmarks to more accurately reflect the full range of utility costs to the implementation of competitive bidding mechanisms that emphasize market-based considerations.

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QUESTIONS FROM SENATOR MCCLURE

PURPA

Question 4: Please provide the Committee a summary of current practices and trends with respect to state public utility commission implementation of the PURPA avoided cost standard and the mandatory purchase requirement.

Answer: PURPA and its implementing regulations are broadly defined, and as a result, each State has the freedom to implement various approaches and methodologies which govern avoided cost determinations and mandatory purchase requirements. Certain States refer to a variety of benchmarks in determining utility avoided cost. Others have turned to competitive bidding procedures which use the utilities self-construction option as a starting point for contract negotiations. In this regard, it should be noted that most agreements between utilities and QFs designate a price for purchased power below the utility's estimated avoided cost.

The following is a representative listing of common avoided cost benchmarks: In Florida, the avoided cost determination of a theoretical plant governs the entire State and QFs rates are set below full avoided cost; in a solicitation issued by Virginia Power, plans for a proxy plant have been used; still other States have determined avoided costs on a utility-by-utility basis; many base their determinations upon the last plant built; some rely upon alternative wholesale purchase; some have even used EPRI Technical Assistance Guide information in arriving at a benchmark.

States also vary in the way they allow capacity and energy contracts to be offered. In California, these proceedings had been governed by a Standard Offer process. However, this process has been suspended and a competitive bidding mechanism is being implemented. Other States have turned to a first-come, first-served approach; others have turned to a competitive bidding approach; some states require set-asides (e.g., 20% renewable); and in Florida, while most QFs are compensated at 75% of avoided cost, waste-to-energy QFs are compensated at 100%. Clearly, every State is different and their needs vary. Fortunately, PURPA has been sufficiently flexible to allow States to evaluate key issues before determining utility avoided costs.

Prepared by: Robert L. San Martin
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QUESTIONS FROM SENATOR MCCLURE

PURPA

Question 5: Which states have adopted competitive bidding for the acquisition of new power supplies? Please summarize how competitive bidding works.

Answer: Competitive bidding programs are still evolving, so there are many variations on the basic process. In general, bidding involves issuing a request for proposals (RFP) to provide power for a given amount of capacity. RFPs are generally developed by an individual utility with state oversight, but in some cases state public utility commissions have been the driving force in RFP development. The RFP lays out the technical, performance and economic standards required to participate in the bidding. Usually the economic requirements of the bids are based on a proxy plant that approximates the utility's self-construction alternative. Once the RFP is issued, bidders are free to offer projects subject to the requirements in the RFP.

Generally, the utility or the public service commission reviews the bids and chooses the winning projects although in some instances a third party is selected for this purpose. Also, in some cases the bids are rejected entirely in favor of other alternatives.

In general, bidding systems are moving toward all source bidding, opening the door to independent power producers, purchases from other utilities, and, in some cases, the utility's own generating alternatives, in addition to qualifying facilites under PURPA. A significant number of demand-side solicitations and bids have also been been incorporated into bidding programs. The key advantage of bidding is that it provides a competitive means of ranking and acquiring the best generating alternatives, especially among QFs. Instead of the first-come, first-served approach that characterized earlier approaches to PURPA implementation, bidding allows potential generators to compete with each other, with utilities, and with other alternative suppliers for available generating markets, thus favoring the most cost-effective and efficient projects.

Under most competitive bidding scenarios, non-utility generators (NUGs) are able to bid on blocks of capacity as opposed to an unspecified amount; bids go to the lowest bidder including non-price factors; and, in addition to QFs, independent power producers (IPPs), other NUGs as well as providers of demand reduction services are able to participate in the bidding process.

According to a recent study prepared by the National Independent Energy Producers (NIEP), seventeen states -- California, Delaware, Florida, Hawaii, Indiana, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Texas, Vermont, and Virginia -- have either adopted or attempted to adopt bidding procedures.

Prepared by: Robert L. San Martin
Date: 8/13/90
Coordinated with:
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Conservation and Renewable Energy

QUESTIONS FROM SENATOR JOHNSTON

PURPA

Question 6: The proponents of S. 2415 assert that small power producers covered by the bill would be able to generate power at competitive prices if the existing size limitations under PURPA are lifted. If the size limitations are lifted, why would the small power producers covered by the bill need any of the attributes of QF status other than Holding Company Act exemption provisions of Section 210 of PURPA be necessary? Doesn't this imply the possibility of subsidy? Please provide a detailed response.

Answer: Removing the size limitation on these types of small power producers won't fundamentally alter the relationship between small power producers and utilities. It will simply remove an impediment to developing some technologies that experience economies of scale at sizes greater than the cap. In effect, it will give an added boost to these types of technologies so that they can realize economics of scale and eventually be able to compete with other technologies. At such time as they are indeed able to truly complete, the attributes of QF status (other than PUHCA exemption) would not be necessary. This is particularly true regarding the PURPA mandatory purchase requirement: If a technologly is competitive in terms of price, reliability, etc., it does not need special treatment.

The fundamental purpose of the mandatory purchase requirement of PURPA was to open the utility market to purchases from qualifying facilities in order to encourage the development of renewable energy and energy-efficient cogeneration. Without a requirement to purchase from non-utility generators, subject to the avoided cost requirements of PURPA, utilities had no obligation to consider other sources of electricity, competitive or not. Since passage of PURPA, utility purchases from QFs and other non-utility generators have increased dramatically, and utilities are increasingly voluntarily soliciting power from non-traditional generators.

The removal of the size limitation does not imply a subsidy to small power producers or other qualifying facilities in that utilities are not obligated to buy power or capacity that is unable to meet the requirements of Section 210 of PURPA. There are no provisions in PURPA or its implementing regulations that require that avoided costs be higher than competitive costs. The Federal Energy Regulatory Commission has stated that avoided costs should neither be greater than nor less than "the price the utility would have paid for comparable power from other sources, including other wholesale sources." (FERC Docket No. RM88-6-000)

Prepared by: Robert L. San Martin
Date: 8/13/90
Coordinated with:
Reviewed by: J. Michael Davis, P.E.
Assistant Secretary
Conservation and Renewable Energy

APPENDIX II

Additional Material Submitted for the Record

GEOTHERMAL RESOURCES ASSOCIATION

6055 East Washington Boulevard Commerce, CA 90040 (213) 725-1139

May 21, 1990

Honorable J. Bennett Johnson
Chairman, Senate Energy Committee
Washington, D.C. 10510

Attention: Bill Conway, Senior Counsel

The Geothermal Resources Association ("GRA") submits the enclosed statement for the record as part of your Committee's Hearings on S. 2415, The solar and Geothermal Power Production Incentives Act of 1990. The GRA is pleased to participate in the development of the proposed amendment. Please keep us advised of progress on this matter.

Sincerely,

Donald C. Liddell
President

DCL:sac

Enclosure

cc: GRA Board of Directors

Honorable James A. McClure
Ranking Member
Senate Energy Committee
Washington, D.C.

Attention: Mr. Howard Useem
Professional Staff Member
U. S. Senate

GEOTHERMAL RESOURCES ASSOCIATION

HEARINGS ON S. 2415

THE SOLAR AND GEOTHERMAL POWER PRODUCTION INCENTIVES ACT OF 1990

GEOTHERMAL RESOURCES ASSOCIATION

The Geothermal Resources Association ("GRA") submits this statement for the record as part of the Hearings on S. 2415, the Solar and Geothermal Power Production Incentives Act of 1990. The GRA has been advised that a scheduled witness from California Energy Company, a member company, was unable to attend the Hearing. We greatly regret that the perspective of geothermal producers was not presented at the hearing.

The GRA strongly supports the proposed amendment.

Geothermal electric generating facilities utilize geothermal resources found at various sites in the United States in the form of geothermal steam or geothermal brine to generate electric energy. Geothermal electric generating facilities also must utilize a limited resource, fossil fuels, to generate electricity. As a result, they do not contribute to the exhaustion of a limited U.S. resource or to the country's trade imbalance. Geothermal electric generating facilities are essentially environmentally benign when compared to the other technologies used to generate electricity.

For the past ten years, geothermal developers have been forced to build power plants that conform to the 80-MW limitation placed on small power producers in order to qualify their facilities as Qualifying Facilities ("QFs") under the Public Utility Regulation Practices Act ("PURPA"). This 80-MW limitation places an extra burden on geothermal development.

Geothermal, unlike many alternative energy technologies, must be developed at the site of the fuel source. Geothermal resources cannot be transported by tank car or truck or by pipelines over long distances. Geothermal resources are generally not found at super high temperatures and pressures. Therefore, efficient use of steam is very important because geothermal power plants cannot operate at high temperatures and pressures like conventional power plants. Artificial limitations upon the size of a geothermal power plant may result in significant inefficiencies and much higher operating costs, leaving geothermal power plants at an economic disadvantage versus other technologies, e.g., gas turbine cogeneration facilities which are not subject to the 80-MW limitation or even other small power producers. At some locations, a unit size of up to 200 MW would be more efficient than 80-MW units.

We believe unit efficiency improvements of 10-25% can be achieved by shorter steam lines between the field and power plant, and larger, more compact power plants. Eliminating the 80-MW limitation would give the geothermal industry the flexibility to make these improvements.

Because of the extensive wellfield development necessary for geothermal development, geothermal facilities utilize substantial amounts of land. Industry experience shows that centrally located clusters of geothermal turbine-generator units can greatly reduce land-use impacts on competing interests. For example, a centrally located geothermal facility minimizes the effect on important agricultural and wildlife lands.

Members of the GRA have raised the issue of a geothermal QF size limitation at the FERC, DOE, and with the Congress. It has been suggested that the authors of the PURPA legislation feared that very large geothermal plants might be built beyond the scope of "small power plants." Industry experience, including utility-owned power plants, suggests that the practical and most efficient power plant size limit is 200 MW for geothermal power.

PURPA has been a positive force in the development of geothermal resources. However, the legislative provisions of so-called "mandatory-buy" and "mandatory interconnection" do not provide a subsidy as many presume. Geothermal projects must still be able to supply electrical energy to utilities at the utilities' "avoided cost," and in practice, QF geothermal projects generally must enter into a competitive bidding process with other generating technologies in order to obtain a power purchase contract. Likewise, connection to the utility grid, although mandatory, is at a price dictated by the utility.

Therefore, notwithstanding the fact that PURPA is a motivating force in the development of QFs, the key to successful operation is development of power systems that can compete effectively in the marketplace. The challenge for the industry is to size geothermal facilities to provide the optimal efficient use of geothermal resources in an operation that can offer consumers a competitive rate.

To date, cogeneration QFs which have no size limitation, and which are not limited to a particular location, have been able to more easily pursue this objective. This size and location flexibility allows them to be more competitive.

The geothermal industry needs a clear signal that larger-than-80-MW power plants can be built in the 90s. Although we are hopeful that Congress would generally work toward a more competitive utility marketplace, we should not be forced to wait for new legislation intended to augment or replace PURPA. Geothermal power is environmentally preferable to other forms of power generation and should be developed to the maximum extent.

Thank you for the opportunity to present our views.

STATEMENT OF GARY E. LAVERING
VICE PRESIDENT
CALIFORNIA ENERGY COMPANY

In Support of S. 2415, The Solar and Geothermal Power Production Incentives Act of 1990

Before the Committee on Energy and Natural Resources
United States Senate
May 15, 1990

Mr. Chairman, on behalf of California Energy Company and the nation's geothermal power production industry I want to thank you for holding this important hearing on S. 2415.

The bill before you is a simple amendment to the Public Utility Regulatory Policies Act of 1978 (PURPA). That Act has been central to our company's ability to become a commercially viable producer of cost competitive, environmentally clean power, using a domestic source of fuel. PURPA provides to qualifying facilities three critical incentives: (1) an exemption from federal and state utility regulations; (2) mandatory purchase of the electricity they generate; and (3) mandatory interconnection with purchasing utilities.

Our company, which is now providing enough electricity to meet the needs of over 250,000 Los Angeles homes, is a testament to the success of that 1978 Act. What began as an experiment has now proven itself fully capable of meeting a significant share of the West's energy needs. However, geothermal power producers, unlike most other independent power producers, are restricted in their ability to fully achieve the goals of PURPA because of a provision of that Act limiting geothermal facilities to no more than 80 megawatts per site. The legislative history of PURPA reveals no rationale for this 80 megawatt cap. We can only assume, therefore, that the limitation was imposed out of a sense of caution, in view of the experimental nature of geothermal power in the United States at the time PURPA was enacted.

As our experience at California Energy demonstrates, geothermal power is no longer experimental. We have proven beyond any doubt that we can successfully develop a major energy resource, and that we can quickly engineer and put into operation 240 megawatts of reliable capacity. In addition, we have succeeded in operating our generating facilities at a capacity factor (percent of time on-line out of total time available) of 92 percent. This compares with an average capacity factor in the electric utility industry of 80 percent for oil and gas generators, 75 percent for coal and 63 percent for nuclear plants. Currently, a primary impediment to our moving rapidly to build new facilities is our inability to achieve the economies of scale which can be realized only through elimination of the 80 megawatt cap in PURPA.

Mr. Chairman, perhaps the best way to illustrate the importance of PURPA and the negative impact of the current 80 megawatt limitation is to describe the experiences of my own company.

While our company has been in existence since 1971, it has only been in the last three years that we have actually generated electrical power on a significant commercial scale. In 1988 we began the year with a single operating turbine. But by the end of that year our flagship COSO project at China Lake, California, had grown into a five unit power complex capable of generating 140 megawatts. By the end of 1989 we added additional capacity bringing the total power generated by the COSO complex up to 240 megawatts. At the present time we must space our operating sites more than one mile apart at locations such as COSO in order to fall within the 80 megawatt per site limitation of PURPA.[1/] The 240 megawatt capacity at our COSO facility represents the total output of three sites spaced more than one mile apart. This spacing of sites is not necessarily dictated by engineering, technical, or geothermal reservoir considerations. It is induced by the need to keep within the 80 megawatt limit and is, therefore, inherently inefficient. This substantial inefficiency has a particularly negative effect on the cost of producing geothermal power.

Compared to conventional fossil fuel power plants a disproportionate share of the cost of producing electricity is

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[1/] The Federal Energy Regulatory Commission has ruled that the output of any facility within one mile of a facility for which PURPA qualification is sought must be included in calculating whether the total output of a facility at a given site falls within the 80 megawatt limit. 18 C.F.R. Sec. 292.204 (a)(2) (1989).

represented by the capital investment required to explore, drill and deliver the underground steam to a generator. For example, since its inception, California Energy has invested close to $180 million in drilling alone. This amount is the dollar investment required to support the 240 megawatt project over the life of the sale contract. By limiting the amount of energy which can be generated at any one site, the 80 megawatt limitation inevitably decreases the operating efficiency of geothermal projects such as COSO. By eliminating this artificial inefficiency, we and other geothermal power producers would have the opportunity to achieve economies and efficiencies of scale necessary to fully maximize the geothermal potential beneath the earth and produce competitively priced power in today's energy market.

In addition to our already operating COSO facility at China Lake, we have numerous geothermal expansion projects planned. Paralleling our COSO development, we continued exploration activities elsewhere in California, Oregon, and Washington. We have just acquired geothermal operations in Utah and Nevada from Chevron. Unless S. 2415 or a similar legislation is passed, these new projects will be subject to the same operating inefficiencies that have limited us at COSO. As a result, the cost for electricity from some projects will be needlessly increased -- all due to an arbitrary restriction, for which no apparent justification exists.

All of this exploration and construction activity requires large amounts of capital. In connection with our exploration activities, we have drilled a total of 98 wells at an average cost of more than $1.5 million apiece. Our existing operations, which only recently began to produce electricity, represent a total investment of over six hundred million dollars. The capital necessary for these operations has been raised through joint venture agreements, public stock offerings, bank financing and other loans. As a practical matter, these financing mechanisms simply would not have been available to us without the benefit of PURPA's exemption from federal and state regulation and other benefits.

In addition, while the demand for energy in California is such that there is a market for electricity we produce, all of our existing contracts require that our plants meet the definition of a qualifying facility under PURPA. Therefore, we simply cannot operate or build any facility -- in violation of these contracts -- which will exceed the megawatt limits imposed by PURPA. The mandatory purchase provisions of PURPA will encourage the development of a competitive power market. We are confident that we can successfully generate electricity in such a market driven environment, provided we can achieve greater economies of scale associated with the geothermal resource which now is restricted arbitrarily by limitations imposed under current law.

In addition to mandatory purchase, PURPA also mandates interconnection to the power grid. Our experience in California, even with a favorable state regulatory environment, has shown that this right of the independent power producer is essential. Without it we could have been seriously delayed in our ability to deliver much needed power to consumers in Los Angeles.

In short, it would not have been possible for us to become what we are today without PURPA, and we cannot fully reach our potential without the elimination of the 80 megawatt limit.

Mr. Chairman, a question you might ask is why should California Energy and similar companies be given the incentive and means to expand geothermal energy production as soon as possible? In response, I would suggest several good reasons. First, there is currently a great need for expanded electric power capacity in the fast growing region of the Far West where most of the nation's geothermal potential is located. Second, while much of this need for expanded capacity will be met by fossil fuel and other power generation technologies, the geothermal industry has a number of unique qualities which suggest that its potential should be maximized as soon as possible.

Leading among these qualities is the fact that we are a domestic U.S. power source. The steam which fuels our plants lies beneath the soil of the United States. It does not have to be imported, and the risks of fuel handling and transportation are minimal.

Unlike fossil fuels of power plants which require combustion to make steam, our steam occurs naturally and requires no combustion. The use of geothermal power is absolutely consistent with the environmental policies being promulgated by the Congress. While a coal-fired generating plant produces 8,500 tons of carbon dioxide per megawatt over a year period and natural gas produces over 3,500 tons of carbon dioxide per megawatt per year, natural steam produces only 10,500 pounds of CO2 per megawatt in a single year -- or just over 5 tons, far less than 1% of the amount of carbon dioxide from either coal or gas.

Equally dramatic differences can be seen in the amount of nitrogen oxides and sulphur oxides released into the atmosphere by geothermal facilities. Coal and oil fired plants emit 46 tons of sulphur oxides and one and a half tons of nitrogen oxide into the air per megawatt annually. Even natural gas produces nearly a half ton per megawatt of sulphur oxide per year. By contrast, geothermal power facilities emit a mere 1000 pounds of sulphur oxides per megawatt during the same period and no nitrogen oxides. The encouragement of geothermal power generation is fully consistent with the clean air and global warming bills now working their way through the Congress.

Natural steam -- the "fuel" for geothermal power stations -- is a renewable resource. Natural steam occurs when the heat of the earth's interior comes in close contact with underground water sources. Modern drilling technology enables wells to tap into this naturally produced steam and hot water. The steam from these wells is piped to the surface and used to power turbines at the wellhead which produce electricity which then can be carried by transmission lines to urban areas. Because the water is continually replenished, natural steam is a renewable resource.

Further, as we have shown at California Energy, natural steam is an extremely reliable source of energy. Geothermal plants are not plagued with reactor shut-downs, inflating oil and gas costs, nor drought induced drops in reservoir water levels. Our 92 percent capacity factor attests to the reliability of geothermal power generation.

Finally, we are cost competitive and can become more so if the arbitrary 80 megawatt limit is removed. The cost of our natural steam, once developed, remains virtually constant and is not subject to inflation. Our turbines are more efficient, cost less to build and operate longer and at high capacity because we have no boilers and combustion. And, we provide one of the best available pollution control systems anywhere as we return the used steam, water and non-condensible gasses back into the earth by injection.

Mr. Chairman, California Energy Company leases 440,000 acres of property in Western states where we believe there is good geothermal potential. With your help we can expedite the use of these indigenous resources to benefit the American energy consumer. Our own analysis shows that in the near term we can increase our production seven-fold. We will be unable to maximize the contribution from this resource, however, unless the arbitrary restrictions contained in present law are eliminated.

The 80 megawatt cap may have been appropriate for an experimental technology. But, we are no longer experimental. Geothermal power in the West is fully competitive with other energy sources. We now need the opportunity to maximize economies of scale and to permit the efficient utilization of the capital investment necessary to fully develop geothermal energy as one of America's energy assets. Elimination of the 80 megawatt cap will enable the geothermal industry to effectively attract investment needed to achieve those economies of scale set by the geothermal resource itself and finally, to continue to provide clean, renewable, competitive energy to our customers.

Thank you for the opportunity to appear before your committee today, Mr. Chairman. I will be happy to answer any questions you may have.

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